AGL RESOURCES INC
Form 10-K/A
November 07, 2014

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

FORM 10-K/A
Amendment No. 1

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

For the fiscal year ended December 31, 2013

Commission File Number 1-14174

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

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

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $5 Par Value	New York Stock Exchange

AGL Resources Inc. is a well-known seasoned issuer.

AGL Resources Inc. is required to file reports pursuant to Section 13 of the Securities Exchange Act.

AGL Resources Inc.: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

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

AGL Resources Inc. believes that during the 2013 fiscal year, its executive officers, directors and 10% beneficial owners subject to Section 16(a) of the Securities Exchange Act complied with all applicable filing requirements, except as set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in AGL Resources Inc.’s Proxy Statement for the 2014 Annual Meeting of Shareholders.

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

The aggregate market value of AGL Resources Inc.'s common stock held by non-affiliates of the registrant (based on the closing sale price on June 29, 2013, as reported by the New York Stock Exchange), was $5,081,511,045.

The number of shares of AGL Resources Inc.'s common stock outstanding as of January 31, 2014 was 118,901,889

TABLE OF CONTENTS

2

Unless the context requires otherwise, references to "we," "us," "our," the "company" or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries.

Explanatory Note:

We are filing this Amendment No. 1 on Form 10-K/A (this "Amended Filing") to our Annual Report on Form 10-K for the year ended December 31, 2013 (the "Original Filing"), to: (i) reissue the Report of Independent Registered Public Accounting Firm to update the firm's opinion regarding the effectiveness of our internal control over financial reporting as of December 31, 2013; (ii) revise management's conclusions regarding internal control over financial reporting and disclosure controls and procedures as of December 31, 2013; (iii) revise the financial statements to adjust certain amounts in the accounting for revenue recognition related to certain of our regulatory infrastructure programs since 1998 and adjust our amortization of intangible assets for our customer relationships and trade names for the years ended December 31, 2013 and 2012, as well as update other previously-identified immaterial adjustments. Accordingly, we hereby amend and replace in their entirety Items 6, 7, 8, 9A and 15 in the Original Filing.

Additionally, we are recasting certain prior period information in our Annual Report on Form 10-K for the year ended December 31, 2013 to conform with segment reporting changes made in connection with the sale of our Tropical Shipping business, as a result of entering into a definitive agreement to sell this business on April 4, 2014. We concluded that this divestiture qualified for discontinued operations treatment of this business during the second quarter of 2014. Accordingly, the operations and cash flows of this business were removed from our ongoing operations and the assets and liabilities of this business were classified as held for sale, as reported in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014.

We did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company's consolidated financial statements. This control deficiency resulted in the misstatement of our regulatory assets and operating revenues and related financial disclosures and resulted in the revision of our consolidated financial statements for the years December 31, 2013, 2012 and 2011 and each of the quarters of March 31, 2014 and June 30, 2014. Additionally, this control deficiency could result in misstatements of the aforementioned accounts and disclosures that would result in a material misstatement of the consolidated financial statements that would not be prevented or detected. Accordingly, our management has concluded that the control deficiency constitutes a material weakness.

As required by Rule 12b-15, our principal executive officer and principal financial officer are providing updated certifications. In addition, we are filing a new consent of PricewaterhouseCoopers LLP. Accordingly, we hereby amend Item 15 in the Original Filing to reflect the filing of the new certifications and consent.

Except as indicated above, this Amended Filing does not purport to reflect any information or events subsequent to the filing date of the Original Filing. As such, this Amended Filing speaks only as of the date the Original Filing was filed, and we have not undertaken herein to amend, supplement or update any information contained in the Original Filing to give effect to any subsequent events. Accordingly, this Amended Filing should be read in conjunction with the Original Filing and any documents filed by us with the Securities and Exchange Commission (SEC) subsequent to the Original Filing, including our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014, filed with the SEC on April 29, 2014, and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014, filed with the SEC on July 30, 2014.

3

GLOSSARY OF KEY TERMS

AFUDC	Allowance for funds used during construction, which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service
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
AGL Resources	AGL Resources Inc., together with its consolidated subsidiaries
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Central Valley	Central Valley Gas Storage, LLC
Chattanooga Gas	Chattanooga Gas Company
Chicago Hub	A venture of Nicor Gas, which provides natural gas storage and transmission-related services to marketers and gas distribution companies
California Commission	California Public Utilities Commission, the state regulatory agency for Central Valley
Compass Energy	Compass Energy Services, Inc., which was sold in 2013
EBIT	Earnings before interest and taxes, the primary measure of our operating segments' profit or loss, which includes operating income and other income and excludes financing costs, including interest on debt and income tax expense
EPA	U.S. Environmental Protection Agency
ERC	Environmental remediation costs associated with our distribution operations segment that are generally recoverable through rate mechanisms
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
Georgia Natural Gas	The trade name under which SouthStar does business in Georgia
Golden Triangle	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London Inter-Bank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Marketers	

	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
MGP	Manufactured gas plant
Moody's	Moody's Investors Service
New Jersey BPU	New Jersey Board of Public Utilities, the state regulatory agency for Elizabethtown Gas
Nicor	Nicor Inc. - an acquisition completed in December 2011 and former holding company of Nicor Gas
Nicor Gas	Northern Illinois Gas Company, doing business as Nicor Gas Company
Nicor Gas Credit Facility	$700 million credit facility entered into by Nicor Gas to support its commercial paper program
NUI	NUI Corporation
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as operating revenues minus cost of goods sold and revenue tax expense
OTC	Over-the-counter
Pad gas	Volumes of non-working natural gas used to maintain the operational integrity of the natural gas storage facility, also known as base gas
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
PGA	Purchased Gas Adjustment
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, doing business as Pivotal Home Solutions
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Seven Seas	Seven Seas Insurance Company, Inc.
SNG	Substitute natural gas, a synthetic form of gas manufactured from coal
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
Term Loan Facility	$300 million credit agreement entered into by AGL Capital to repay the $300 million senior notes that matured in 2011
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, and also the name used throughout this filing to describe the business operations of our former cargo shipping segment (excluding Triton), which now has been classified as discontinued operations and held for sale
U.S.	United States
VaR	Value-at-risk is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given

	degree of probability.
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
WACOG	Weighted average cost of gas
WNA	Weather normalization adjustment

PART II

ITEM 6. REVISED SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data." Material changes from 2011 to 2012 are primarily due to the Nicor merger which closed on December 9, 2011.

	2013(1)	2012 (1)	2011 (1)(2)	2010 (2)(3)	2009 (2)(3)
Dollars and shares in millions, except per share amounts	Revised	Revised	Revised		
Income statement data					
Operating revenues	$4,209	$3,562	$2,305	$2,373	$2,317
Operating expenses					
Cost of goods sold	2,110	1,583	1,085	1,164	1,142
Operation and maintenance (4)	887	816	497	497	497
Depreciation and amortization	397	394	182	160	158
Nicor merger expenses (4)	-	20	57	6	-
Taxes other than income taxes	187	159	57	46	44
Total operating expenses	3,581	2,972	1,878	1,873	1,841
Gain on disposition of assets	11	-	-	-	-
Operating income	639	590	427	500	476
Other income (expense)	16	24	7	(1)	9
EBIT	655	614	434	499	485
Interest expense, net	170	183	134	109	101
Income before income taxes	485	431	300	390	384
Income tax expense	177	157	121	140	135
Income from continuing operations	308	274	179	250	249
Income from discontinued operations, net of tax	5	1	-	-	-
Net income	313	275	179	250	249
Less net income attributable to the noncontrolling interest	18	15	14	16	27
Net income attributable to AGL Resources Inc.	$295	$260	$165	$234	$222
Per common share information					
Diluted weighted average common shares outstanding	118.3	117.5	80.9	77.8	77.1
Diluted earnings per common share (5)					
Continuing operations	$2.45	$2.20	$2.04	$3.00	$2.88
Discontinued operations	0.04	0.01	-	-	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$2.49	$2.21	$2.04	$3.00	$2.88
Dividends declared per common share	$1.88	$1.74	$1.90	$1.76	$1.72
Dividend payout ratio	76 %	79 %	93 %	58 %	60 %
Dividend yield (6)	4.0 %	4.4 %	4.5 %	4.9 %	4.7 %
Price range:					

High	$49.31		$42.88		$43.69		$40.08		$37.52	
Low	$38.86		$36.59		$34.08		$34.21		$24.02	
Close (7)	$47.23		$39.97		$42.26		$35.85		$36.47	
Market value (7)	$5,615		$4,711		$4,946		$2,800		$2,826	
Statements of Financial Position data (7)										
Total assets	$14,550		$14,070		$13,862		$7,481		$7,045	
Property, plant and equipment – net	8,643		8,205		7,741		4,396		4,146	
Short-term debt	1,171		1,377		1,321		733		602	
Long-term debt	3,813		3,553		3,578		1,971		1,974	
Total debt	4,984		4,930		4,899		2,704		2,576	
Total equity	3,613		3,391		3,305		1,836		1,819	
Financial ratios (7)										
Debt	58	%	59	%	60	%	60	%	59	%
Equity	42	%	41	%	40	%	40	%	41	%
Total	100	%	100	%	100	%	100	%	100	%
Return on average equity	8.4	%	7.8	%	6.4	%	12.8	%	12.7	%

(1)Amounts revised for prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

(2)Material changes from 2011 to 2012 are primarily due to the Nicor merger on December 9, 2011. Tropical Shipping was acquired in the Nicor merger, therefore, there were no changes as a result of the September 2014 divestiture to 2010 or 2009.

(3)Income statement data does not reflect adjustments, as discussed in Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein as they were inconsequential to these years. However, we have revised total assets and property, plant and equipment, net.

(4)Transaction expenses associated with the Nicor merger were excluded from operation and maintenance expenses and presented separately.

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

(6)Dividends declared per common share during the fiscal period divided by market value per common share as of the last day of the fiscal period.

(7)As of the last day of the fiscal period.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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 complementary to the distribution of natural gas. Our operating segments consist of the following four operating and reporting segments – distribution operations, retail operations, wholesale services and midstream operations and one non-operating segment - other. These segments are consistent with how management views and operates our business. Amounts shown in this Item 7, unless otherwise indicated, exclude assets held for sale and discontinued operations. See Note 14 under Item 8 for additional information. The following table provides certain information on our segments.

	EBIT (1)			Assets (1)			Capital Expenditures (1)		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Distribution operations	84 %	84 %	93 %	82 %	82 %	81 %	93 %	84 %	85 %
Retail operations	20	18	21	5	4	4	1	1	1
Wholesale services	-	-	1	8	9	9	-	-	-
Midstream operations	(2)	2	2	5	5	5	2	8	8
Other/intercompany eliminations	(2)	(4)	(17)	-	-	1	4	7	6
Total	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

In the third quarter of 2014, we adjusted the accounting treatment for our previously-reported non-cash revenue recognition associated with our regulatory infrastructure programs. The adjustments did not affect previously-reported operating cash flows, nor are they expected to affect capital expenditure plans or dividend payments. The infrastructure replacement programs are expected to generate the same levels of return as previously communicated, as all amounts will be recovered in accordance with allowed recovery mechanisms. The adjustment relates only to the timing of recognition and does not impact rates charged to customers. These adjustments impacted our distribution operations segment. Additionally, we adjusted the amortization of intangible assets for customer relationships and trade names in our retail operations segment to reflect the amortization expense on a basis consistent with the pattern of undiscounted cash flows used to determine their fair values. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information on these adjustments. As indicated in the tables below, these adjustments resulted in the following impact to our previously reported results for distribution operations and retail operations.

	2013			2012			2011		
In millions	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)	Operating margin (1) (2)	Operating expenses (2) (3)	EBIT (1)	Operating margin (1) (2)	Operating expenses (2)	EBIT (1)
Distribution operations									
As filed	$ 1,660	$ 1,093	$ 582	$ 1,571	$ 1,048	$ 532	$ 963	$ 557	$ 412
Adjustment	(45)	(10)	(36)	(19)	(4)	(15)	(13)	(2)	(11)
Revised	$ 1,615	$ 1,083	$ 546	$ 1,552	$ 1,044	$ 517	$ 950	$ 555	$ 401

Retail operations									
As filed	$ 294	$ 157	$ 137	$ 247	$ 131	$ 116	$ 168	$ 75	$ 93
Adjustment	-	5	(5)	-	5	(5)	-	-	-
Revised	$ 294	$ 162	$ 132	$ 247	$ 136	$ 111	$ 168	$ 75	$ 93

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.
(2) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income, and EBIT to income before income taxes and net income is contained in "Results of Operations" herein. See Note 13 to our Consolidated Financial Statements under Part II, Item 8 herein for additional segment information.
(3) Operating margin and operating expenses are adjusted for revenue tax expenses which are passed directly through to our customers.

On April 4, 2014 we entered into a definitive agreement to sell Tropical Shipping, which historically operated within our cargo shipping segment. We closed the sale of Tropical Shipping in September 2014. The operations of Tropical Shipping have been classified as discontinued operations in our consolidated financial statements, and the business is no longer treated as a separate segment for financial reporting purposes. Accordingly, in this Management's Discussion and Analysis of Financial Condition and Results of Operations, all references to continuing operations exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not a part of the sale and has been reclassified into our other segment. The sale of Tropical Shipping will allow us to focus on growing our core business of operating regulated utilities and complementary non-regulated energy businesses and provide us with flexibility around our long-term financing plans. For additional information on our discontinued operations, see Note 14 to our Consolidated Financial Statements under Part II, Item 8 herein for additional segment information.

In 2013, our net income attributable to AGL Resources Inc. was $295 million, an increase of $35 million compared to 2012 as we benefited from colder-than-normal weather as compared to the historically warm weather in 2012. Excluding weather, we achieved growth in our operating margins during 2013 primarily as a result of contributions from our regulatory infrastructure programs in distribution operations, targeted acquisition growth in retail operations and significant improvement in commercial activity in our wholesale services, as well as the gain on the sale of Compass Energy, offset by mark-to-market accounting hedge losses recorded during the second half of 2013. These losses are temporary and expected to be recovered primarily in 2014.

In 2014, our priorities are consistent with the direction we have taken the Company over the last three years. We will remain focused on efficient operations across all of our businesses, including offsetting inflationary pressures by aggressive cost controls, spreading costs across a broader customer base and sizing our operations to properly reflect market challenges. Several of our specific business objectives are detailed as follows:

- Distribution Operations: Invest necessary capital to enhance and maintain safety and reliability; remain a low-cost leader within the industry; opportunistically expand the system and capitalize on potential customer conversions. We intend to continue investing in our regulatory infrastructure programs in Georgia, Virginia, New Jersey and Tennessee to minimize regulatory lag and the recovery cycle. During 2014 we intend to submit to the Illinois Commission a regulatory infrastructure program in Illinois, to become effective in January 2015. We continue to effectively manage costs and leverage our shared services model across our businesses to largely overcome inflationary effects.
- Retail Operations: Maintain operating margins in Georgia and Illinois while continuing to expand into other profitable retail markets; integrate our warranty businesses and expand our overall market reach through partnership opportunities with our affiliates. We expect the Georgia retail market to remain highly competitive; however, our operating margins are forecasted to remain stable with modest growth from the acquisitions completed in 2013 and expansion into new markets.
- Wholesale Services: Maximize strong storage and transportation rollout value created in 2013; effectively perform on existing asset management agreements and expand customer base; and maintain cost structure in line with market fundamentals. We anticipate low volatility in certain areas of our portfolio; however, volatility is expected to increase in the supply-constrained Northeast corridor. We further anticipate narrow seasonal storage spreads will continue to be challenges in 2014.
- Midstream Operations: Optimize storage portfolio, including expiring contracts, pursue LNG transportation opportunities and lower development expenses.

Additionally, we will maintain our strong balance sheet and liquidity profile, solid investment grade ratings and our commitment to sustainable annual dividend growth. For additional information on our operating segments, see Note 13 to our consolidated financial statements under Part II, Item 8 herein and Item 1, “Business” in the Original Filing.

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 following table provides more information regarding the components of our operating revenues.

In millions	2013	2012	2011 (2)
Residential (1)	$2,422	$2,011	$1,065
Commercial	696	656	467
Transportation	487	474	389

Industrial	180	262	289
Other	424	159	95
Total operating revenues (1)	$4,209	$3,562	$2,305

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

(2) Our results of operations for the year ended December 31, 2011 includes 22 days of activity from the subsidiaries acquired from Nicor.

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

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of 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 and midstream operations segments since it is a direct measure of operating margin before overhead costs. You should not consider operating margin an alternative to, or a more meaningful indicator of, our operating performance than operating income, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP. In addition, operating margin may not be comparable to similarly titled measures of other companies.

We also believe presenting the non-GAAP measurements of basic and diluted earnings per share - as adjusted, which excludes Nicor merger-related expenses and the additional accrual for the Nicor Gas PBR issue, 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 last three years.

In millions, except per share amounts	2013 (1)	2012 (1)	2011 (1)
Operating revenues	$ 4,209	$3,562	$ 2,305
Cost of goods sold	(2,110)	(1,583)	(1,085)
Revenue tax expense (2)	(110)	(85)	(9)
Operating margin	1,989	1,894	1,211
Operating expenses (3) (4)	(1,471)	(1,369)	(736)
Revenue tax expense (2)	110	85	9
Gain on disposition of assets	11	-	-
Nicor merger expenses (3)	-	(20)	(57)
Operating income	639	590	427
Other income	16	24	7
EBIT	655	614	434
Interest expense, net	(170)	(183)	(134)
Income before income taxes	485	431	300
Income tax expense	(177)	(157)	(121)
Income from continuing operations	308	274	179
Income from discontinued operations, net of tax	5	1	-
Net income	313	275	179
Less net income attributable to the noncontrolling interest	18	15	14
Net income attributable to AGL Resources Inc.	$ 295	$260	$ 165
Per common share data			
Diluted earnings per common share from continuing operations (5) (6)	$ 2.45	$2.20	$ 2.04
Diluted earnings per common share from discontinued operations	0.04	0.01	-
Additional accrual for Nicor Gas PBR issue	-	0.04	-
Transaction costs of Nicor merger (2)	-	0.11	0.80
Diluted earnings per share - as adjusted (5)	$ 2.49	$2.36	$ 2.84

(1) Amount includes prior period adjustments and the sale of Tropical Shipping. See Note 14 and Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

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

(3)

Operating expenses associated with the merger with Nicor are shown separately to better compare year-over-year results and include $20 million ($13 million net of tax) in 2012 and $57 million ($48 million net of tax) in 2011. Additionally, in 2011, transaction costs of the Nicor merger include debt issuance costs and interest expense on pre-funding the cash portion of the purchase consideration of $25 million ($16 million net of taxes).

(4) Total operating expenses in 2013 were unfavorably impacted by increased incentive compensation accruals of $37 million compared to the prior year. These amounts were above targeted levels in 2013.

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

(6) Gain on disposition of assets increased basic and diluted EPS by $0.04 in 2013.

In 2013 our income from continuing operations increased by $34 million, or 12% compared to 2012.

- The overall increase was primarily the result of increased operating margin at distribution operations and retail operations due to weather that was both colder-than-normal and colder than the same period last year, increased regulatory infrastructure program revenues at Atlanta Gas Light, the acquisition of service contracts and residential and commercial energy customer relationships in our retail operations segment, as well as lower depreciation expense at Nicor Gas.
- The increase was unfavorably impacted by mark-to-market accounting hedge losses in our wholesale services segment during the second half of 2013, offset by higher commercial activity and the $11 million pre-tax gain on the sale of Compass Energy.
- Our midstream operations segment was unfavorable compared to 2012 due to the $8 million loss associated with the termination of the Sawgrass Storage project, as well as lower contracted firm rates at Jefferson Island and higher operating expenses at Golden Triangle, Central Valley and Pivotal LNG resulting from full year operations in 2013 as compared to partial year operations in 2012.
- Favorability year-over-year also was partially offset by higher incentive compensation expenses in most of our businesses as our incentive compensation expense was above targeted levels in 2013 based on improved financial and operational performance compared to significantly below targeted annual levels in 2012 due to below target performance. In addition, our bad debt expense increased at distribution operations and 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.
  - In 2012 we recorded $20 million ($13 million net of tax) of Nicor merger related expenses.
- In 2013 our interest expense decreased by $13 million compared to 2012. This decrease was the result of overall lower interest rates mostly offset by higher average debt outstanding primarily as a result of issuing $500 million of senior notes in place of variable-rate debt.
- In 2013 our income tax expense increased by $20 million or 13% compared to 2012 primarily due to higher consolidated earnings, as previously discussed. Our effective tax rate was 37.9% in 2013 and 2012. Our estimated effective tax rate for 2014 is also 37.9%.

In 2012 our net income from continuing operations increased by $95 million, or 53% compared to 2011.

- The increase was primarily the result of increased operating income at distribution operations and retail operations as a result of the Nicor merger, and increased regulatory infrastructure program revenues at Atlanta Gas Light.
- This increase was partially offset by the effect of warmer-than-normal weather in our distribution operations and retail operations segments, and significantly lower margins at wholesale services resulting from mark-to-market accounting hedge losses.
    - In 2011 we recorded $57 million ($48 million net of tax) of Nicor merger related expenses.
- In 2012 our interest expense increased by $49 million or 37% compared to 2011. This increase was the result of higher average debt outstanding primarily as a result of the additional long-term debt issued to fund the Nicor merger and the long-term debt assumed in the transaction.
- In 2012 our income tax expense increased by $36 million or 30% compared to the same period in 2011 primarily due to higher consolidated earnings. Our effective tax rate was 42.4% in 2011 primarily due to the non-deductible merger transaction expenses in 2011.

The variances for each operating segment are contained within the year-over-year discussion on the following pages.

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 utility 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)		Years ended December 31,			2013 vs. 2012	2012 vs. 2011	2013 vs. normal	2012 vs. normal	2011 vs. normal
	Normal (1)	2013	2012	2011	colder (warmer)	colder (warmer)	colder (warmer)	colder (warmer)	colder (warmer)
Year ended December 31,									
Illinois (2)	5,729	6,305	4,863	5,892	30 %	(17)%	10 %	(15)%	3 %
Georgia	2,600	2,689	1,934	2,454	39 %	(21)%	3 %	(26)%	(6)%
Quarter ended December 31,									
Illinois (2)	2,039	2,383	1,890	1,810	26 %	4 %	17 %	(7)%	(11)%
Georgia	1,009	1,049	878	852	19 %	3 %	4 %	(13)%	(16)%

(1) Normal represents the ten-year average from January 1, 2003 through December 31, 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 established by the Illinois Commission in our last rate case, is 2,020 for the fourth quarter and 5,600 for the 12 months from 1998 through 2007.

During 2013 we experienced weather in Illinois that was 10% colder-than-normal and 30% colder than the same period in the prior year. Georgia also experienced 3% colder-than-normal weather, and 39% colder than the same period last year. For our Illinois weather risk associated with Nicor Gas, we implemented a corporate weather hedging program in the second quarter of 2013 that utilizes OTC weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather. For January through April of 2014, we have purchased a put option that would partially offset lower operating margins resulting from reduced customer usage in the event of warmer-than-normal weather, but would not be exercised in the event of colder-than-normal weather and, therefore, not offset higher margins if Heating Degree Days for the period are at normal or colder-than-normal levels. We will continue to use available methods to mitigate our exposure to weather in Illinois for future periods.

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 energy customers at retail operations are primarily located in Georgia and Illinois.

Customers and service contracts (average end-use, in thousands)	Year ended December 31, 2013	2012	2011	2013 vs. 2012 change #	%	2012 vs. 2011 change #	%
Distribution operations customers	4,479	4,459	4,454	20	0.4%	5	0.1%
Retail operations							
Energy customers (1)	619	623	578	(4)	(1)%	45	8%
Service contracts (2)	1,127	684	710	443	65%	(26)	(4)%
Market share in Georgia	31%	32%	33%		(3)%		(3)%

(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 decrease for the year ended 2012 is primarily due to our contract to serve approximately 50,000 customer equivalents that ended on April 1, 2012, which was partially offset by the increase due to the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013.

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

We anticipate overall utility customer growth trends for 2013 to continue in 2014 based on an expectation of continuing improvement in the economy and continuing low natural gas prices. We use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include adding residential customers, multifamily complexes and commercial and industrial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new natural gas related programs, products and services to enhance customer growth, mitigate customer attrition and increase operating revenues. These programs generally emphasize natural gas as the fuel of choice for customers and seek to expand the use of natural gas through a variety of promotional activities. We also target customer conversions to natural gas from other energy sources emphasizing the pricing advantage of natural gas. These programs focus on premises that could be connected to our distribution system at little or no cost to the customer. In cases where conversion cost can be a disincentive, we may employ rebate programs and other assistance to address customer cost issues.

Retail operations' market share in Georgia has decreased slightly primarily as a result of a highly competitive marketing environment, which we expect will continue for the foreseeable future. In 2013 our retail operations segment expanded its energy customers and its service contracts through acquisitions and entering into new markets. We anticipate this expansion will provide growth opportunities in future years.

Volume Our natural gas volume metrics for distribution operations and retail operations, present the effects of weather and 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. Our volume metrics are presented in the following table:

Volumes	Year ended December 31,			2013 vs. 2012 % change	2012 vs. 2011 % change
Distribution operations (In Bcf)	2013	2012	2011		
Firm	720	606	247	19 %	145 %
Interruptible	111	107	105	4 %	2 %
Total	831	713	352	17 %	103 %
Retail operations (In Bcf)					
Georgia firm	38	31	35	23 %	(11)%
Illinois	9	8	-	13 %	-
Other (1)	8	8	10	-	(20)%
Wholesale services					
Daily physical sales (Bcf/day)	5.73	5.54	5.21	3 %	6 %

	As of December 31,		
	2013	2012	2011
Midstream operations			
Working natural gas capacity (in Bcf)	31.8	31.8	13.5
% of firm capacity under subscription by third parties (2)	33 %	46 %	68 %

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

(2) The percentage of capacity under subscription does not include 3.5 Bcf of capacity under contract with Sequent at December 31, 2013, 3 Bcf of capacity under contract with Sequent at December 31, 2012 and 4 Bcf of capacity under contract with Sequent at December 31, 2011.

Segment information Operating margin, operating expenses and EBIT information for each of our segments are contained in the following tables for the last three years.

	Operating Margin (1) (2)			Operating Expenses (2) (3)			EBIT (1)		
In millions	2013	2012	2011 (4)	2013	2012	2011 (4)	2013 (5)	2012	2011 (4)
Distribution operations(6)	$ 1,615	$ 1,552	$ 950	$ 1,083	$ 1,044	$ 555	$ 546	$ 517	$ 401
Retail operations (6)	294	247	168	162	136	75	132	111	93
Wholesale services	39	50	57	53	54	52	(3)	(3)	5
Midstream operations	41	46	37	46	38	28	(10)	10	9
Other (7)	8	7	4	25	40	79	(10)	(21)	(74)
Intercompany eliminations	(8)	(8)	(5)	(8)	(8)	(5)	-	-	-
Consolidated (6)	$ 1,989	$ 1,894	$ 1,211	$ 1,361	$ 1,304	$ 784	$ 655	$ 614	$ 434

(1) Operating margin is a non-GAAP measure. A reconciliation of operating revenue and operating margin to operating income and EBIT to earnings before income taxes and net income is contained in "Results of Operations." See Note 13 to our consolidated financial statements under Part II, Item 8 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 $20 million and $57 million in Nicor merger transaction expenses for 2012 and 2011, respectively, and an $8 million accrual in 2012 for the Nicor Gas PBR issue.
(4) The 2011 amounts only include 22 days of Nicor activity from December 10, 2011 through December 31, 2011.
(5) EBIT for 2013 includes $11 million pre-tax gain on sale of Compass Energy in our wholesale services segment and an $8 million pre-tax loss associated with the termination of the Sawgrass Storage project within our midstream operations segment.
(6) Amount includes prior period adjustments. See Note 15 to our consolidated financial statements under Part II, Item 8 herein for additional information.
(7) Our other segment includes our investment in Triton, which was formerly part of our cargo shipping segment that is now classified as discontinued operations. See Note 14 to our consolidated financial statements under Part II, Item 8 set forth herein.

The EBIT of our distribution operations, retail operations and wholesale services segments are seasonal. During the Heating Season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. Occasionally in the summer, wholesale services operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain Consolidated Statements of Financial Position items across quarters, including receivables, unbilled revenue, inventories and short-term debt. However, these items are comparable when reviewing our annual results.

Approximately 67% of these segments' operating revenues and 70% of these segments' EBIT for the year ended December 31, 2013 were generated during the first and fourth quarters of 2013. Our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality.

Distribution Operations

Our distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the seven states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders. With the exception of Atlanta Gas Light, our second largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. We have various mechanisms, such as weather normalization mechanisms at our utilities and weather derivative instruments that limit our exposure to weather changes within typical ranges in their respective service areas. During 2013, colder-than-normal weather increased our operating margin at our utilities, primarily at Nicor Gas by $12 million compared to expected levels based on 10-year normal weather. During 2012, warmer-than-normal weather decreased our operating margin by $24 million.

In millions	2013	2012
EBIT - prior year (1)	$517	$401
Operating margin		
Increased revenues from regulatory infrastructure programs, primarily at Atlanta Gas Light (1)	4	10
Increased operating margin from Nicor Gas as a result of the Nicor merger in December 2011	-	581
Increased rider revenues primarily as a result of energy efficiency program recoveries at Nicor Gas	19	15
Increased (decreased) operating margin mainly driven by weather, customer usage and customer growth	45	(6)
(Decreased) increased margin from gas storage carrying amounts at Atlanta Gas Light	(5)	2
Increase in operating margin (1)	63	602
Operating expenses		
Increased (decreased) incentive compensation costs that reflect year over year performance (1)	37	(7)
Increased rider expenses primarily as a result of energy efficiency programs at Nicor Gas	19	15
Increased depreciation expense as a result of increased PP&E from infrastructure additions and improvements (1)	11	7
Increased (decreased) bad debt expenses as a result of change in natural gas prices and weather	4	(5)
Increased outside services and other expenses mainly as a result of maintenance programs (1)	1	5
Increased expenses for Nicor Gas as a result of the Nicor merger in December 2011	-	461
Decreased depreciation expense at Nicor Gas due to deprecation study approval effective August 30, 2013	(19)	-
Decreased operation and maintenance expense at Nicor Gas related to the 2012 PBR accrual	(8)	-
(Decreased) increased pension and health benefits expenses primarily related to retiree health care costs and change in actuarial gains and losses	(6)	13
Increase in operating expenses (1)	39	489
Increase in other income primarily from AFUDC equity from STRIDE Projects at Atlanta Gas Light	5	3
EBIT - current year (1)	$546	$517

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

In accordance with an order issued by the Georgia Commission, where AGL Resources makes a business acquisition that reduces the cost allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a ten-year period. In December 2013 we filed a Report of Synergy Savings with the Georgia Commission in connection with the Nicor acquisition. If and when approved, the net savings should result in annual rate reductions to the firm customers of Atlanta Gas Light of $5 million. We expect the Georgia Commission to rule on the report in the second quarter of 2014.

Retail Operations

Our retail operations segment, which consists of 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 partially mitigate potential weather impacts. During 2013, colder-than-normal weather increased operating margin by $9 million. During 2012, warmer-than-normal weather decreased operating margin by $9 million. Additionally, during 2013, our retail operations' EBIT was favorably impacted by $12 million as a result of the acquisition of additional customer and service contracts.

In millions	2013	2012
EBIT - prior year (1)	$111	$93
Operating margin		
Increased margin as a result of the Nicor merger in December 2011	-	76
Increased (decreased) operating margin primarily related to average customer usage in Georgia due to demand and weather, net of weather hedges	17	(10)
Increased margin primarily due to acquisitions in January and June 2013 and expansions into additional retail energy markets	35	-
(Decrease) increase related to change in gas costs and from retail price spreads, partially offset by changes to customer portfolio	(11)	10
Storage inventory write-down (LOCOM) adjustment	3	1
Other	3	2
Increase in operating margin	47	79
Operating expenses		
Increased expenses as a result of the Nicor merger in December 2011	-	64
Increased expenses primarily due to acquisitions in January and June 2013	23	-
Increased (decreased) bad debt expenses related to change in natural gas prices and weather	3	(5)
Other	-	2
Increase in operating expenses (1)	26	61
EBIT - current year (1)	$132	$111

(1) Amount includes prior period adjustments. See Note 15 to our Consolidated Financial Statements under Part II, Item 8 herein for additional information.

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. We principally use physical and financial arrangements to reduce the risks associated with fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, our reported earnings for wholesale services reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as gains or losses within our operating revenues.

In millions	2013	2012
EBIT - prior year	$(3)	$5
Operating margin		
Change in commercial activity in 2013 largely driven by the withdrawal of a portion of the storage inventory economically hedged at the end of 2012, weather and increased cash optimization opportunities in the supply-constrained Northeast corridor	86	5
Change in value of storage hedges as a result of changes in NYMEX natural gas prices	(30)	(23)
Change in value of transportation and forward commodity hedges from price movements related to natural gas transportation positions (1)	(70)	(11)

Change in storage inventory LOCOM adjustment, net of estimated recoveries	3	22
Decrease in operating margin	(11)	(7)
Operating expenses		
Decreased expenses due to sale of Compass Energy in May 2013	(4)	-
Increased payroll, benefits and incentive compensation costs, offset by lower other costs	3	2
(Decrease) increase in operating expenses	(1)	2
Gain on sale of Compass Energy	11	-
(Decrease) increase in other income	(1)	1
EBIT - current year	$(3)	$(3)

(1) 2011 excluded forward commodity hedge losses associated with counterparty bankruptcy and Marcellus take-away constraint losses.

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 2013, commercial activity increased significantly due to:

- increased cash optimization opportunities related to certain of our transportation portfolio positions, particularly in the Northeastern U.S.
- 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
- the effects of colder weather

The 2012 change in commercial activity was primarily due to losses in 2011 associated with constraints of natural gas purchased from producers in the Marcellus shale gas producing region and credit losses associated with a counterparty that filed for bankruptcy during 2011. Commercial activity in 2012 was also impacted by the abundance of natural gas supply due to shale production, which reduced price volatility and transportation spreads. Additionally, 2012 was one of the warmest years in recorded history causing a reduction in customer demand and transportation spreads.

Change in storage and transportation hedges Seasonal (storage) and geographical location (transportation) spreads and overall natural gas price volatility continued to remain low relative to historical periods. Storage hedge losses in 2013 are primarily due to the increase in natural gas prices during the fourth quarter of 2013 as compared to storage hedge gains last year resulting from a downward movement in natural gas prices. Losses in our transportation hedge positions in 2013 are the result of widening transportation basis spreads, associated with colder-than-normal weather and higher demand during the second half of 2013 experienced at natural gas receipt and delivery points primarily in the Northeast corridor related to natural gas transportation constraints in the region. These losses are temporary and based on current expectations will be recovered in 2014 through 2016 (with the majority recognized in 2014) via the physical flow of natural gas and utilization of the contracted transportation capacity.

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

In millions	2013	2012	2011
Commercial activity recognized	$129	$43	$38
(Loss) gain on transportation and forward commodity hedges	(73)	(3)	8
(Loss) gain on storage hedges	(16)	14	37
Inventory LOCOM adjustment, net of estimated current period recoveries	(1)	(4)	(26)
Operating margin	$39	$50	$57

For more information on Sequent's expected operating revenues from its storage inventory and transportation and forward commodity hedges in 2014 and discussion of commercial activity, see Item 1 "Business" under the caption Wholesale Services within our Original Filing.

Midstream Operations

Our midstream operations segment's primary activity is operating non-utility storage and pipeline facilities including the development, acquisition and operation of high-deliverability underground natural gas storage assets. Our midstream operations segment also includes an equity investment in Sawgrass Storage, a joint venture between us and a privately held energy exploration and production company. The joint venture decided in December 2013 to terminate the development of the Sawgrass Storage facility. For more information, see Note 10 to our consolidated financial statements under Item 8 herein.

In millions	2013	2012
EBIT - prior year	$10	$9
Operating margin		
Decreased margin from Central Valley Storage as a result of hedge gains in 2012 that did not occur in 2013; increased in 2012 due to the Nicor merger in December 2011	(2)	8
Decreased revenues at Jefferson Island as a result of lower subscription rates	(3)	(4)
Increased revenues primarily at Golden Triangle as a result of Cavern 2 beginning commercial service in 2012 and Cavern 1 working gas capacity project in 2013, as well as revenue due to entry into LNG markets	-	5
(Decrease) increase in operating margin	(5)	9

Operating expenses		
Increased expense from Central Valley Storage as a result of the Nicor merger in December 2011 and the facility beginning commercial service during the second quarter of 2012	4	7
Increased operating and depreciation expenses primarily due to entry into the LNG markets and Cavern 2 at Golden Triangle beginning commercial service in 2012	4	3
Increase in operating expenses	8	10
Impairment loss at Sawgrass Storage	(8)	-
Increase in other income from equity interest in Horizon Pipeline	1	2
Other (expense) income	(7)	2
EBIT - current year	$(10)	$10

Liquidity and Capital Resources

Overview The acquisition of natural gas and pipeline capacity, payment of dividends and funding of working capital needs primarily related to our natural gas inventory are our most significant short-term financing requirements. The liquidity required to fund these short-term needs is primarily provided by our operating activities, and any needs not met, are primarily satisfied with short-term borrowings under our commercial paper programs, which are supported by the AGL Credit Facility and the Nicor Gas Credit Facility. For more information on the seasonality of our short-term borrowings, see “Short-term Debt” later in this section.

The need for long-term capital is driven primarily by capital expenditures and maturities and refinancing of long-term debt. Periodically, we raise funds supporting our long-term cash needs from the issuance of long-term debt or equity securities. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner. Consistent with this strategy, in May 2013 we issued $500 million in 30-year senior notes with a 4.4% fixed interest rate.

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 $499 million at December 31, 2013.

We believe the amounts available to us under our long-term debt, 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.

Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes active management of the percentage of total debt relative to total capitalization, appropriate mix of debt with fixed to floating interest rates (our variable debt target is 20% to 45% of total debt), as well as the term and interest rate profile of our debt securities.

As of December 31, 2013, our variable-rate debt was $1.4 billion, or 28%, of our total debt, compared to $1.5 billion, or 32%, as of December 31, 2012. The decrease was primarily due to decreased commercial paper borrowings. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

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," within our Original Filing for additional information on items that could impact our liquidity and capital resource requirements.

Short-term Debt The following table provides additional information on our short-term debt throughout the year.

In millions	Year-end balance outstanding (1)	Daily average balance outstanding (2)	Minimum balance outstanding (2)	Largest balance outstanding (2)
Commercial paper - AGL Capital	$ 857	$ 777	$ 380	$ 1,064
Commercial paper - Nicor Gas	314	99	-	340
Senior Notes - Current Portion	-	64	-	225
Capital leases - Current Portion	-	-	-	1

Total short-term debt and current portions of long-term debt and capital leases	$ 1,171	$ 940	$ 380	$ 1,630

(1) As of December 31, 2013.

(2) For the twelve months ended December 31, 2013. The minimum and largest balances outstanding for each debt instrument occurred at different times during the year. Consequently, the total balances are not indicative of actual borrowings on any one day during the year.

The largest, minimum and daily average balances borrowed under our commercial paper programs are important when assessing the intra-period fluctuations of our short-term borrowings and potential liquidity risk. The fluctuations are due to our seasonal cash requirements to fund working capital needs, in particular the purchase of natural gas inventory, margin calls and collateral.

Cash requirements generally increase between June and December as we purchase natural gas in advance of the Heating Season. The timing differences of when we pay our suppliers for natural gas purchases and when we recover our costs from our customers through their monthly bills can significantly affect our cash requirements. Our short-term debt balances are typically reduced during the Heating Season, as a significant portion of our current assets, primarily natural gas inventories, are converted into cash.

The AGL Credit Facility and the Nicor Gas Credit Facility can be drawn upon to meet working capital and other general corporate needs. The interest rates payable on borrowings under these facilities are calculated either at the alternative base rate, plus an applicable margin, or LIBOR, plus an applicable interest margin. The applicable interest margin used in both interest rate calculations will vary according to AGL Capital's and Nicor Gas' current credit ratings.

In November 2013, the lenders for our two credit facilities consented to our request to extend the maturity date of each facility by one year, in accordance with the terms of the respective agreements. The AGL Credit Facility and Nicor Gas Credit Facility maturity dates were extended to November 10, 2017 and December 15, 2017, respectively. The terms, conditions and pricing under the agreements remain unchanged. At December 31, 2013 and 2012, we had no outstanding borrowings under either credit facility.

The timing of natural gas withdrawals is dependent on the weather and natural gas market conditions, both of which impact the price of natural gas. Increasing natural gas commodity prices can have a significant impact on our commercial paper borrowings. Based on current natural gas prices and our expected purchases during the upcoming injection season, we believe that we have sufficient liquidity to cover our working capital needs.

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 December 31, 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. Commercial paper borrowings reduce availability of these credit facilities.

Long-term Debt Our long-term debt matures more than one year from December 31, 2013 and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1989; senior notes; first mortgage bonds; and gas facility revenue bonds.

Our long-term cash requirements primarily depend upon the level of capital expenditures, long-term debt maturities and decisions to refinance long-term debt. The following table summarizes our long-term debt issuances over the last three years.

	Issuance Date	Amount (in millions)	Term (in years)	Interest rate	
Gas facility revenue bonds (1)		$200	10-20	Floating rate	
Senior notes (2)	May 2013	$500	30	4.4	%
Senior notes - Series A (3) (4)	October 2011	$120	5	1.9	%
Senior notes - Series B (3)	October 2011	$155	7	3.5	%
Senior notes (3)	September 2011	$200	30	5.9	%
Senior notes (3)	September 2011	$300	10	3.5	%
Senior notes (5)	March 2011	$500	30	5.9	%

(1) During the first quarter of 2013, we refinanced the gas facility revenue bonds. We had no cash receipts or payments in connection with the refinancing. See Note 8 to our consolidated financial statements under Item 8 herein for more information.
(2) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $225 million we borrowed to repay our senior notes that matured on April 15, 2013.
(3) The net proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.
(4) In October 2014 the interest rate for these senior notes will change to a floating rate.
(5) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $300 million we borrowed to repay our senior notes that matured on January 14, 2011. The remaining proceeds were used to pay a portion of the cash consideration and expenses incurred in connection with the Nicor merger.

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 financial performance and financial condition and reevaluate their ratings of our long-term debt and short-term borrowings, our corporate ratings and our ratings outlook. There is no guarantee that a rating will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. A credit rating is not a recommendation to buy, sell or hold securities and each rating should be evaluated independently of other ratings.

Factors we consider important to assessing our credit ratings include our Consolidated Statements of Financial Position, leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. As of December 31, 2013, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $11 million to continue conducting business with certain customers. The following table summarizes our credit ratings as of January 31, 2014 and reflects upgrades by Moody’s for certain of our ratings compared to 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-1	F1
Senior unsecured	BBB+	A3	BBB+	BBB+	A2	A+
Senior secured	n/a	n/a	n/a	A	Aa3	AA-
Ratings outlook	Stable	Stable	Stable	Stable	Stable	Stable

A downgrade in our current ratings, particularly below investment grade, would increase our borrowing costs and could limit our access to the commercial paper market. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

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

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

Our credit facilities each include a financial covenant that requires us to maintain a ratio of total debt to total capitalization of no more than 70% at the end of any fiscal month. However, we typically seek to maintain these ratios at levels between 50% and 60%, except for temporary increases related to the timing of acquisition and financing activities. Adjusting for these items, the following table contains our debt-to-capitalization ratios for December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2013	2012	2013	2012
Debt-to-capitalization ratio as calculated from our Consolidated Statement of Financial Position	58 %	59 %	54 %	55 %
Adjustments (1)	(1)	(1)	1	-
Debt-to-capitalization ratio as calculated from our credit facilities	57 %	58 %	55 %	55 %

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

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2013 and 2012. For more information on our default provisions, see Note 8 to our consolidated financial statements under Item 8 herein.

Cash Flows

We prepare our Consolidated Statements of Cash Flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in derivative instrument assets and liabilities, deferred income taxes, gains or losses on the sale of assets and changes in the Consolidated Statements of Financial Position for working capital from the beginning to the end of the period. The following table provides a summary of our operating, investing and financing cash flows for the last three years.

In millions	2013	2012	2011
Net cash provided by (used in) (1):			
Operating activities	$971	$1,003	$451
Investing activities	(876)	(786)	(1,339)
Financing activities	(121)	(155)	933
Net (decrease) increase in cash and cash equivalents – continuing operations	(26)	53	31
Net increase in cash and cash equivalents - discontinued operations	-	9	14
Cash and cash equivalents (including held for sale) at beginning of period	131	69	24
Cash and cash equivalents (including held for sale) at end of period	105	131	69
Less cash and cash equivalents held for sale at end of period	24	23	14
Cash and cash equivalents (excluding held for sale) at end of period	$81	$108	$55

(1) Excludes activity for discontinued operations.

Cash Flow from Operating Activities 2013 compared to 2012 Our net cash flow provided by operating activities in 2013 was $971 million, a decrease of $32 million or 3% from 2012. The decrease was primarily related to 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) deferred income taxes, due to the net change in mark to market activity at wholesale services combined with less cash provided from accelerated tax depreciation in 2013 than in 2012. This decrease in cash provided by operating activities was partially offset by increased cash provided by (i) lower payments for incentive compensation in 2013 as a result of reduced earnings in 2012 as compared to 2011 and (ii) trade payables, other than energy marketing, due to higher gas purchase volumes primarily at distribution operations and retail operations resulting from colder weather in 2013.

2012 compared to 2011 Our net cash flow provided by operating activities in 2012 was $1,003 million, an increase of $552 million or 122% from 2011. The increase was primarily related to the recovery of working capital from the companies acquired in the December 2011 merger with Nicor. Cash provided by operations changed $89 million driven by derivative financial instrument assets and liabilities, primarily a result of the change in forward NYMEX prices at wholesale services year-over-year, and $70 million driven by a decrease in Sequent's park and loan gas transactions due to lower volumes and decreased prices. Additionally, we had a $26 million increase in operating cash flow from Elizabethtown Gas' recoverable derivative position as a result of changes in forward NYMEX prices. These increases were partially offset by a decrease in recovery of working capital during 2012 as a result of warmer-than-normal weather. Our increased operating cash flow in 2012 was also impacted by a decrease in cash used for margin deposits of $94 million due to the change in cash collateral value on our hedged positions and a $121 million decrease in trade payables mainly due to lower natural gas prices and purchased volumes in 2012.

Cash Flow from Investing Activities The increase in net cash flow used in investing activities was primarily a result of our $122 million acquisition of customer service contracts during the first quarter of 2013 and our $32 million acquisition of residential and commercial energy customer relationships in Illinois during the second quarter of 2013, both in our retail operations segment. This increase was partially offset by decreased spending for PP&E expenditures of $45 million, a net decrease in short-term investments of $7 million and $12 million from the sale of Compass Energy.

Our estimated PP&E expenditures for 2014 and our actual PP&E expenditures incurred in 2013, 2012 and 2011 are within the following categories and are quantified in the following table.

- Distribution business - primarily includes new construction and infrastructure improvements
- Regulatory infrastructure programs - programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth. These programs include STRIDE at Atlanta Gas Light, SAVE at Virginia Natural Gas, and an enhanced infrastructure program at Elizabethtown Gas
- Natural gas storage - underground natural gas storage facilities at Golden Triangle, Jefferson Island and Central Valley
- Other - primarily includes information technology and building and leasehold improvements

In millions	2014 (1)	2013	2012	2011 (2)
Distribution business	$503	$421	$371	$159
Regulatory infrastructure programs	163	226	263	192
Natural gas storage	4	6	55	22
Other	99	78	86	54
Total	$769	$731	$775	$427

(1) Estimated PP&E expenditures.
(2) Only includes Nicor expenditures subsequent to the merger date of December 9, 2011.

Our PP&E expenditures were $730 million for the year ended December 31, 2013, compared to $775 million for the same period in 2012.The decrease of $45 million, or 6%, was primarily due to decreased spending of $49 million on our natural gas storage projects consisting of $35 million at Central Valley and $14 million at Golden Triangle. Additionally, capital expenditures decreased $35 million for strategic projects and $16 million for utility infrastructure enhancement projects at Elizabethtown Gas. These decreases were partially offset by increased expenditures of $54 million for regulatory infrastructure programs at Atlanta Gas Light and $9 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our PP&E expenditures were $775 million for the year ended December 31, 2012, compared to $427 million for the same period in 2011.The increase of $348 million, or 81%, was primarily due to $188 million of PP&E expenditures at Nicor Gas and $31 million of PP&E expenditures at Central Valley, both of which were acquired through our merger with Nicor in December 2011. Additionally, capital expenditures increased $63 million for pipeline replacement projects, $21 million for i-SRP projects and $10 million for i-CGP projects at Atlanta Gas Light, as well as $16 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our estimated expenditures for 2014 include discretionary spending for capital projects principally within the distribution business, regulatory infrastructure programs, natural gas storage and other categories. We continuously evaluate whether or not to proceed with these projects, reviewing them in relation to various factors, including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities During 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 our other financing arrangements. 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.

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 with net proceeds of $494 million 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.

Nicor Merger Financing The total value of the consideration paid to Nicor common shareholders was $2.5 billion. Upon closing the merger, we assumed the first mortgage bonds of Nicor Gas, which at December 31, 2011 had principal balances totaling $500 million and maturity dates between 2016 and 2038. These bonds were recorded at their estimated fair value of $599 million on the date the merger closed. Additionally, we assumed $424 million in short-term debt upon closing the merger.

During 2011, we secured the permanent debt financing we used to pay the cash portion of the purchase consideration. This included approximately $200 million from our $500 million in senior notes that were issued in March 2011, $500 million in senior notes that were issued in September 2011, and $275 million in senior unsecured notes that were issued in the private placement market in October 2011.

For more information on our financing activities, see short and long-term debt within "Liquidity and Capital Resources."

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $17 million in 2013, $14 million in 2012 and $16 million in 2011 in our Consolidated Statements of Cash Flows as financing activities. The primary reason for the increase in the distribution to Piedmont during the current year was increased earnings for 2012 compared to 2011 and a distribution of excess working capital from the joint venture in 2013. Additionally, we received $22.5 million from Piedmont in 2013 to maintain their 15% ownership interest after we contributed our Illinois Energy business to the SouthStar joint venture.

Dividends on Common Stock Our common stock dividend payments were $222 million in 2013, $203 million in 2012 and $148 million in 2011. The increases were generally the result of the annual dividend increase of $0.04 per share for each of the last three years. However, as a result of the Nicor merger, AGL Resources shareholders of record as of the close of business on December 8, 2011 received a pro rata dividend of $0.0989 per share for the stub period, which accrued from November 19, 2011 and totaled $7 million. The dividend payments made in February 2012 were reduced by this stub period dividend. For information about restrictions on our ability to pay dividends on our common stock, see Note 9 to our consolidated financial statements under Item 8 herein.

Shelf Registration In July 2013, we filed a shelf registration statement with the SEC, which expires in 2016. Under this shelf registration statement, debt securities will be issued by AGL Capital and related guarantees will be issued by AGL Resources under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Mellon Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series, subject to our AGL Credit Facility financial covenant related to total debt to total capitalization.

Off-balance sheet arrangements We have certain guarantees, as further described in Note 11 to our consolidated financial statements under Item 8 herein. We believe the likelihood of any such payment under these guarantees is remote. No liability has been recorded for these guarantees.

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. The following table illustrates our expected future contractual obligation payments and commitments and contingencies as of December 31, 2013.

In millions	Total	2014	2015	2016	2017	2018	2019 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$ 3,706	$ -	$ 200	$ 545	$ 22	$ 155	$ 2,784
Short-term debt	1,171	1,171	-	-	-	-	-
Environmental remediation liabilities (2)	447	70	82	80	48	63	104
Pipeline replacement program costs (2)	5	5	-	-	-	-	-
Total	$ 5,329	$ 1,246	$ 282	$ 625	$ 70	$ 218	$ 2,888
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$ 2,298	$ 733	$ 507	$ 299	$ 138	$ 102	$ 519
Interest charges (5)	2,899	185	175	161	147	145	2,086
Operating leases (6)	203	28	27	24	21	17	86
Asset management agreements (7)	19	8	5	4	2	-	-
Standby letters of credit, performance/surety bonds (8)	27	27	-	-	-	-	-
Other	5	1	2	2	-	-	-
Total	$ 5,451	$ 982	$ 716	$ 490	$ 308	$ 264	$ 2,691

(1) Excludes the $82 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $9 million interest rate swaps fair value adjustment.

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

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

(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 31 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2013, and is valued at $136 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2013 and the maturity date of the underlying debt instrument. As of December 31, 2013, we have $52 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2014.

(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with authoritative guidance related to leases. Our operating leases are primarily for real estate.

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

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

Standby letters of credit and performance/surety bonds. We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and the maximum potential amount of future payments that could be required of us as the guarantor. We would expect to fund these contingent financial commitments with operating and financing cash flows.

Pension and other retirement obligations. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Pension Protection Act. We calculate any required pension contributions using the traditional unit credit cost method; however, additional voluntary contributions are periodically made. Contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. The contributions represent the portion of the other retirement costs which we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions in all of our jurisdictions, except Illinois, have phase-ins that defer a portion of the retirement benefit expenses for retirement plans other than pensions for future recovery. We recorded a regulatory asset for these future recoveries of $108 million as of December 31, 2013 and $215 million as of December 31, 2012. In Illinois, all accrued retirement plan expenses are recovered through base rates. See Note 6 to our consolidated financial statements under Item 8 herein for additional information about our pension and other retirement plans.

In 2013, no contributions were required to our qualified pension plans. In 2012, we contributed $40 million to these qualified pension plans. Effective December 31, 2012, we merged the NUI Pension and Nicor Pension plans into the AGL Pension plan. Based on the estimated funded status of the merged AGL Pension plan, we do not expect any required contribution to the plan in 2014. We may, at times, elect to contribute additional amounts to the AGL Pension Plan in accordance with the funding requirements of the Pension Protection Act.

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 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. The following is a summary of our most critical accounting policies, which represent those that may involve a higher degree of uncertainty, judgment and complexity. Our significant accounting policies are described in Note 2 to our consolidated financial statements under Item 8 herein.

Accounting for Rate-Regulated Subsidiaries

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs or expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for estimated expenditures that have not yet been incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulatory commissions. At December 31, 2013, our regulatory assets were $819 million and regulatory liabilities were $1.7 billion. At December 31, 2012, our regulatory assets were $1.0 billion and regulatory liabilities were $1.6 billion.

We believe our regulatory assets are probable of recovery. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during future rate proceedings. We 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. Additionally, while some regulatory liabilities would be written off, others may continue to be recorded as liabilities but not as regulatory liabilities.

Although the natural gas distribution industry is competing with alternative fuels, primarily electricity, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under the guidance remains appropriate. It is also our opinion that all regulatory assets are probable of recovery in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider. The regulatory liabilities that do not represent revenue collected from customers for expenditures that have not yet been incurred are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

The majority of our regulatory assets and liabilities are included in base rates except for the recoverable regulatory infrastructure program costs, recoverable ERC, energy efficiency plans, the bad debt rider and accrued natural gas costs, which are recovered through specific rate riders on a dollar-for-dollar basis. The rate riders that authorize the recovery of regulatory infrastructure program costs and natural gas costs include both a recovery of cost and a return on investment during the recovery period. Nicor Gas' rate riders for environmental costs and energy efficiency costs provide a return of investment and expense including short-term interest on reconciliation balances. However, there is no interest associated with the under or over collections of bad debt expense.

Our natural gas distribution operations and certain regulated transmission and storage operations meet the criteria of a cost-based, rate-regulated entity under accounting principles generally accepted in the U.S. Accordingly, the financial results of these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory commissions to which we are subject.

As a result, certain costs that would normally be expensed under accounting principles generally accepted in the U.S. are permitted to be capitalized or deferred on the balance sheet because it is probable that they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations.

Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Assets and liabilities recognized as a result of rate regulation would be written off as extraordinary items in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2013, would result in 6% and 12% decreases in total assets and total liabilities, respectively. For more information on our regulated assets and liabilities, see Note 3 to our consolidated financial statements under Item 8 herein.

Impairment of Goodwill and Long-Lived Assets, including Intangible Assets

Goodwill We do not amortize our goodwill, but test it for impairment at the reporting unit level during the fourth fiscal quarter or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. A reporting unit is the operating segment, or a business one level below the operating segment (a component), if discrete financial information is prepared and regularly reviewed by management. Components are aggregated if they have similar economic characteristics.

As part of our impairment test, an initial assessment is made by comparing the fair value of a reporting unit with its carrying value, including goodwill. If the fair value is less than the carrying value, an impairment is indicated, and we must perform a second test to quantify the amount of the impairment. In the second test, we calculate the implied fair value of the goodwill by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value of the entire reporting unit determined in step one of the assessment. If the carrying value of the goodwill exceeds the implied fair value of the goodwill, we record an impairment charge. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective.

Under the income approach, fair value is determined based upon the present value of estimated future cash flows discounted at an appropriate risk-free rate that takes into consideration the time value of money, inflation and the risks inherent in ownership of the business being valued. These forecasts contain a degree of uncertainty, and changes in these projected cash flows could significantly increase or decrease the estimated fair value of the reporting unit. For the regulated reporting units, a fair recovery of and return on costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach included return on equity for the regulated reporting units, long-term growth rates used to determine terminal values at the end of the discrete forecast period, 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 is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area.

Under the market approach, fair value is determined by applying market multiples to forecasted cash flows. This method uses metrics from similar publicly traded companies in the same industry to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

The goodwill impairment testing develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions which are subjective in nature and inherent to a discounted cash flows calculation. We weight the results of the two valuation approaches to estimate the fair value of each reporting unit.

The significant assumptions that drive the estimated fair values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC) and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2013 indicated that the estimated fair value of all but one of our reporting units with goodwill was in excess of the carrying value by approximately 20% to almost 500%, and none of the reporting units were at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of the storage and fuels reporting unit with $14 million of goodwill, exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2021 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year off of which we estimated the terminal value. In the terminal year we assumed a long-term earnings growth rate of 2.5% that we believe is appropriate given the current economic and industry-specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2012 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next eight years. Should this growth not occur, this reporting unit will likely fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2013 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods. For more information, see “Acquisitions” in Note 2 to our consolidated financial statements under Item 8 herein.

We will continue to monitor this reporting unit for impairment and note that continued declines in contracted capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in future failure of the step 1 goodwill impairment test and may also result in a future impairment of goodwill. If subscription rates and subscribed volumes decline, the estimated future cash flows will decrease from our current estimates. As of December 31, 2013, we estimate that 15% of our future cash flows will be received over the next 10 years, an additional 20% over the following 10 years and 65% in periods thereafter over the remaining useful lives of our storage facilities. 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.

Long-Lived Assets We depreciate or amortize our long-lived assets and other intangible assets, over their estimated useful lives. Currently, we have no indefinite-lived intangible assets. We assess our long-lived assets and other intangible assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset.

We determined that there were no long-lived asset impairments in 2013; however, if our storage facilities within midstream operations experience further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of long-lived assets.

Derivatives and Hedging Activities

The authoritative guidance to determine whether a contract meets the definition of a derivative instrument, contains an embedded derivative requiring bifurcation, or qualifies for hedge accounting treatment is voluminous and complex. The treatment of a single contract may vary from period to period depending upon accounting elections, changes in our assessment of the likelihood of future hedged transactions or new interpretations of accounting guidance. As a result, judgment is required in determining the appropriate accounting treatment. In addition, the estimated fair value of derivative instruments may change significantly from period to period depending upon market conditions, and changes in hedge effectiveness may impact the accounting treatment.

The authoritative guidance related to derivatives and hedging requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the Consolidated Statements of Financial Position as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase or normal sale, it is exempted from fair value accounting treatment and is, instead, subject to traditional accrual accounting. We utilize market data or assumptions that market participants would use in pricing the derivative asset or liability, including assumptions about risk and the risks inherent in the inputs of the valuation technique.

The authoritative accounting guidance requires that changes in the derivatives' fair value are recognized concurrently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance allows derivative gains and losses to offset related results of the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until the hedged transaction occurs in the case of a cash flow hedge. Additionally, the guidance requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment.

Nicor Gas and Elizabethtown Gas utilize derivative instruments to hedge the price risk for the purchase of natural gas for customers. These derivatives are reflected at fair value and are not designated as accounting hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers, subject to review by the applicable state regulatory commissions, and therefore have no direct impact on earnings. Unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities.

We use derivative instruments primarily to reduce the impact to our results of operations due to the risk of changes in the price of natural gas. The fair value of natural gas derivative instruments used to manage our exposure to 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. For the derivatives utilized in retail operations and wholesale services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in our results of operations in the period of change. Retail operations records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

Additionally, as required by the authoritative guidance, we are required to classify our derivative assets and liabilities based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. The determination of the fair value of our derivative instruments incorporates various factors required under the guidance. These factors include:

- the credit worthiness of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit);
- events specific to a given counterparty; and
- the impact of our nonperformance risk on our liabilities.

We have recorded derivative instrument assets of $119 million at December 31, 2013 and $144 million at December 31, 2012. Additionally, we have recorded derivative liabilities of $80 million at December 31, 2013 and $39 million at December 31, 2012. We recorded losses on our Consolidated Statements of Income of $97 million in 2013 and gains of $10 million in 2012 and $24 million in 2011.

If there is a significant change in the underlying market prices or pricing assumptions we use in pricing our derivative assets or liabilities, we may experience a significant impact on our financial position, results of operations and cash flows. Our derivative and hedging activities are described in further detail in Note 2 and Note 5 to our consolidated financial statements under Item 8 herein and Item 1, "Business" within our Original Filing.

Contingencies

Our accounting policies for contingencies cover a variety of activities that are incurred in the normal course of business and generally relate to contingencies for potentially uncollectible receivables, and legal and environmental exposures. We accrue for these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered, and an amount can be reasonably estimated. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future.

Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in the estimates related to contingencies could have a negative impact on our consolidated results of operations, cash flows or financial position. Our contingencies are further discussed in Note 11 to our consolidated financial statements under Item 8 herein.

Pension and Other Retirement Plans

Our pension and other retirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates. We annually review the estimates and assumptions underlying our pension and other retirement plan costs and liabilities and update them when appropriate. The critical actuarial assumptions used to develop the required estimates for our pension and other retirement plans include the following key factors:

- assumed discount rates;
- expected return on plan assets;
- the market value of plan assets;
- assumed mortality table;
- assumed health care costs;
- assumed compensation increases;
- assumed rates of retirement; and
- assumed rates of termination.

The discount rate is utilized in calculating the actuarial present value of our pension and other retirement obligations and our annual net pension and other retirement costs. When establishing our discount rate, with the assistance of our actuaries, we consider high-grade bond indices. The single equivalent discount rate is derived by applying the appropriate spot rates based on high quality (AA or better) corporate bonds that have a yield higher than the regression mean yield curve, to the forecasted future cash flows in each year for each plan.

The expected long-term rate of return on assets is used to calculate the expected return on plan assets component of our annual pension and other retirement plans costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater or less than the assumed rate, that year's annual pension or other retirement plan cost is not affected; rather, this gain or loss reduces or increases future pension or other retirement plan costs.

Equity market performance and corporate bond rates have a significant effect on our reported results. For the AGL pension plan, market performance affects our market-related value of plan assets (MRVPA), which is a calculated value and differs from the actual market value of plan assets. The MRVPA recognizes differences between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year smoothing weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology, which affects the expected return on plan assets component of pension expense.

In addition, differences between actuarial assumptions and actual plan experience are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the projected benefit obligation (PBO) or the MRVPA for the AGL pension plan. The excess, if any, is amortized over the average remaining service period of active employees.

During 2013, we recorded net periodic benefit costs of $57 million (pre-capitalization) related to our defined pension and other retirement benefit plans. We estimate that in 2014, we will record net periodic pension and other retirement benefit costs in the range of $38 million to $42 million (pre-capitalization), a $15 million to $19 million decrease compared to 2013. In determining our estimated expenses for 2014, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans	Other retirement plans
Discount rate	5.00 %	4.70 %
Expected return on plan assets	7.75 %	7.75 %

The actuarial assumptions we use may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal and retirement rates, and longer or shorter life spans of participants. The following table illustrates the effect of changing the critical actuarial assumptions for our pension and other retirement plans while holding all other assumptions constant:

Dollars in millions	Percentage-point change in assumption	Increase (decrease) in PBO/ APBO	Increase (decrease) in cost
Expected long-term return on plan assets	+ / - 1 %	$ - / -	$ (9) / 9
Discount rate	+ / - 1 %	$ (154) / 171	$ (13) / 13

See Note 4 and Note 6 to our consolidated financial statements under Item 8 herein for additional information on our pension and other retirement plans.

Income Taxes

The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We account for income taxes in accordance with authoritative guidance, which requires that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. The guidance also requires that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some or all of the deferred tax assets will not be realized.

Deferred tax liabilities are estimated based on the expected future tax consequences of items recognized in the financial statements. Additionally, during the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. As a result, we recognize tax liabilities based on estimates of whether additional taxes and interest will be due. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected, in our judgment, to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability and we would be required to record a deferred tax liability of $31 million if we no longer asserted indefinite reinvestment of undistributed foreign earnings.

For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. In addition, we operate within multiple tax jurisdictions and we are subject to audits in these jurisdictions. These audits can involve complex issues, which may require an extended period of time to resolve. We maintain a liability for the estimate of potential income tax exposure and, in our opinion, adequate provisions for income taxes have been made for all years reported.

We had a $22 million valuation allowance on $215 million of deferred tax assets ($146 million of long term and $69 million of current) as of December 31, 2013, reflecting the expectation that most of these assets will be realized. Our gross long-term deferred tax liability totaled $1,760 million at December 31, 2013. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our taxes.

We are required to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Additionally, we recognize accrued interest related to uncertain tax positions in interest expense, and penalties in operating expense in the Consolidated Statements of Income. As of December 31, 2013, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of AGL Resources Inc.:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of AGL Resources Inc. and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Management and we previously concluded that the Company maintained effective internal control over financial reporting as of December 31, 2013. However, management has subsequently determined that a material weakness in internal control over financial reporting related to ineffective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs regarding the accounting for its regulated infrastructure programs which existed as of that date. Accordingly, management's report has been restated and our present opinion on internal control over financial reporting, as presented herein, is different from that expressed in our previous report. In our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control - Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because a material weakness in internal control over financial reporting related to ineffective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs regarding the accounting for its regulated infrastructure programs. A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the annual or interim financial statements will not be prevented or detected on a timely basis. The material weakness referred to above is described in the accompanying Management's Report on Internal Control Over Financial Reporting. We considered this material weakness in determining the nature, timing, and extent of audit tests applied in our audit of the 2013 consolidated financial statements and our opinion regarding the effectiveness of the Company's internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Atlanta, Georgia

February 6, 2014, except with respect to our opinion on the consolidated financial statements insofar as it relates to the effects of discontinued operations described in Note 14, as to which the date is September 2, 2014, and except for the effects of the revision described in Note 15 to the consolidated financial statements and the matter described in the penultimate paragraph of Management's Report on Internal Control Over Financial Reporting, as to which the date is November 7, 2014

Management's Report on Internal Control Over Financial Reporting (as restated)

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision of and with the participation of our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in the Internal Control – Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO Framework") as of December 31, 2013.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of the Company's annual or interim consolidated financial statements will not be prevented or detected on a timely basis.

We did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company's consolidated financial statements. This control deficiency resulted in the misstatement of our regulatory assets and operating revenues and related financial disclosures and resulted in the revision of our consolidated financial statements for the years December 31, 2013, 2012 and 2011 and each of the quarters of March 31, 2014 and June 30, 2014. Additionally, this control deficiency could result in misstatements of the aforementioned accounts and disclosures that would result in a material misstatement of the consolidated financial statements that would not be prevented or detected. Accordingly, our management has concluded that the control deficiency constitutes a material weakness.

In Management's Report on Internal Control Over Financial Reporting included in our original Annual Report on Form 10-K for the year ended December 31, 2013, based on our evaluation under the COSO Framework, our management, including our principal executive officer and principal financial officer, concluded that we maintained effective internal control over financial reporting as of December 31, 2013. Our management has subsequently concluded that the material weakness described above existed as of December 31, 2013. As a result, our management has concluded that we did not maintain effective internal control over financial reporting as of December 31, 2013, based on the criteria in the COSO Framework. Accordingly, management has restated its report on internal control over financial reporting.

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

November 7, 2014

/s/ John W. Somerhalder II	/s/ Andrew W. Evans
John W. Somerhalder II	Andrew W. Evans
Chairman, President and Chief Executive Officer	Executive Vice President and Chief Financial Officer

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - ASSETS
REVISED

In millions	As of December 31, 2013	2012
Current assets		
Cash and cash equivalents	$81	$108
Short-term investments	49	56
Receivables		
Energy marketing	786	672
Gas	385	362
Unbilled revenues	268	235
Other	83	60
Less allowance for uncollectible accounts	29	28
Total receivables, net	1,493	1,301
Inventories		
Natural gas	637	679
Other	21	20
Total inventories	658	699
Assets held for sale	283	291
Regulatory assets	114	98
Derivative instruments	99	130
Prepaid expenses	63	132
Other	55	21
Total current assets	2,895	2,836
Long-term assets and other deferred debits		
Property, plant and equipment	10,938	10,319
Less accumulated depreciation	2,295	2,114
Property, plant and equipment, net	8,643	8,205
Goodwill	1,827	1,776
Regulatory assets	705	939
Intangible assets	145	71
Long-term investments	113	128
Pension assets	117	33
Derivative instruments	20	14
Other	85	68
Total long-term assets and other deferred debits	11,655	11,234
Total assets	$14,550	$14,070

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION - LIABILITIES AND EQUITY
REVISED

In millions, except share amounts	As of December 31, 2013	2012
Current liabilities		
Short-term debt	$1,171	$1,377
Energy marketing trade payables	671	611
Other accounts payable - trade	421	325
Regulatory liabilities	183	161
Customer deposits and credit balances	136	143
Accrued taxes	85	51
Derivative instruments	75	33
Accrued environmental remediation liabilities	70	57
Accrued wages and salaries	66	27
Accrued interest	52	53
Liabilities held for sale	40	39
Accrued regulatory infrastructure program costs	5	121
Current portion of long-term debt and capital leases	-	226
Other	143	112
Total current liabilities	3,118	3,336
Long-term liabilities and other deferred credits		
Long-term debt	3,813	3,327
Accumulated deferred income taxes	1,628	1,561
Regulatory liabilities	1,518	1,477
Accrued pension and retiree welfare benefits	404	508
Accrued environmental remediation liabilities	377	387
Derivative instruments	5	6
Other	74	77
Total long-term liabilities and other deferred credits	7,819	7,343
Total liabilities and other deferred credits	10,937	10,679
Commitments, guarantees and contingencies (see Note 11)		
Equity		
Common shareholders' equity		
Common stock, $5 par value; 750,000,000 shares authorized; outstanding: 118,888,876 shares at December 31, 2013 and 117,855,075 shares at December 31, 2012	595	590
Additional paid-in capital	2,054	2,015
Retained earnings	1,063	990
Accumulated other comprehensive loss	(136)	(218)
Treasury shares, at cost: 216,523 shares at December 31, 2013 and 2012	(8)	(8)
Total common shareholders' equity	3,568	3,369
Noncontrolling interest	45	22
Total equity	3,613	3,391
Total liabilities and equity	$14,550	$14,070

See Notes to Consolidated Financial Statements.

29

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
REVISED

	Years ended December 31,		
In millions, except per share amounts	2013	2012	2011
Operating revenues (includes revenue taxes of $112 for 2013, $86 for 2012 and $9 for 2011)	$4,209	$3,562	$2,305
Operating expenses			
Cost of goods sold	2,110	1,583	1,085
Operation and maintenance	887	816	497
Depreciation and amortization	397	394	182
Nicor merger expenses	-	20	57
Taxes other than income taxes	187	159	57
Total operating expenses	3,581	2,972	1,878
Gain on disposition of assets	11	-	-
Operating income	639	590	427
Other income, net	16	24	7
Interest expenses, net	(170)	(183)	(134)
Total other expense	154	159	127
Income before income taxes	485	431	300
Income tax expenses	177	157	121
Income from continuing operations	308	274	179
Income from discontinued operations, net of tax	5	1	-
Net income	313	275	179
Less net income attributable to the noncontrolling interest	18	15	14
Net income attributable to AGL Resources Inc.	$295	$260	$165
Per common share data			
Basic earnings per common share			
Continuing operations	$2.46	$2.21	$2.05
Discontinued operations	0.04	0.01	-
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$2.50	$2.22	$2.05
Diluted earnings per common share			
Continuing operations	$2.45	$2.20	$2.04
Discontinued operations	0.04	0.01	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$2.49	$2.21	$2.04
Cash dividends declared per common share	$1.88	$1.74	$1.90
Weighted average number of common shares outstanding			
Basic	117.9	117.0	80.4
Diluted	118.3	117.5	80.9

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
REVISED

	Years Ended December 31,		
In millions	2013	2012	2011
Net income	$313	$275	$179
Other comprehensive income (loss), net of tax			
Retirement benefit plans, net of tax			
Actuarial gain (loss) arising during the period (net of income tax of $46, $16 and $47)	66	(17)	(71)
Prior service costs arising during the period (net of income tax of $1)	-	1	-
Reclassification of actuarial losses to net benefit cost (net of income tax of $10, $9 and $7)	15	13	9
Reclassification of prior service costs to net benefit cost (net of income tax of $2, $2 and $3)	(3)	(2)	(3)
Retirement benefit plans, net	78	(5)	(65)
Cash flow hedges, net of tax			
Net derivative instrument gains (losses) arising during the period (net of income tax of $1 and $2)	1	(2)	(5)
Reclassification of realized derivative losses to net income (net of income tax of $1, $3 and $1)	3	6	3
Cash flow hedges, net	4	4	(2)
Other comprehensive income (loss), net of tax	82	(1)	(67)
Comprehensive income	395	274	112
Less comprehensive income attributable to noncontrolling interest	18	15	14
Comprehensive income attributable to AGL Resources Inc.	$377	$259	$98

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY
REVISED

	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
As of December 31, 2010, as filed	78.0	$ 391	$ 631	$ 943	$ (150)	$ (2)	$ 23	$ 1,836
Adjustments (1)	-	-	-	(27)	-	-	-	(27)
As of December 31, 2010, revised	78.0	$ 391	$ 631	$ 916	$ (150)	$ (2)	$ 23	$ 1,809
Net income	-	-	-	165	-	-	14	179
Other comprehensive loss	-	-	-	-	(67)	-	-	(67)
Dividends on common stock ($1.90 per share)	-	-	-	(148)	-	-	-	(148)
Distributions to noncontrolling interests	-	-	-	-	-	-	(16)	(16)
Stock granted, share-based compensation, net of forfeitures	-	-	(11)	-	-	-	-	(11)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.5	3	20	-	-	(3)	-	20
Purchase of treasury shares	-	-	-	-	-	(2)	-	(2)
Issuance of shares for Nicor merger	38.2	191	1,332	-	-	-	-	1,523
Stock-based compensation expense, net of tax	-	-	8	-	-	-	-	8
As of December 31, 2011	117.0	$ 586	$ 1,989	$ 933	$ (217)	$ (7)	$ 21	$ 3,305
Net income	-	-	-	260	-	-	15	275
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)

Dividends on common stock ($1.74 per share)	-	-	-	(203)	-	-	-	(203)
Distributions to noncontrolling interests	-	-	-	-	-	-	(14)	(14)
Stock granted, share-based compensation, net of forfeitures	-	-	(10)	-	-	-	-	(10)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.6	3	19	-	-	(1)	-	21
Stock-based compensation expense, net of tax	-	-	8	-	-	-	-	8
As of December 31, 2012	117.9	$ 590	$ 2,015	$ 990	$ (218)	$ (8)	$ 22	$ 3,391
Net income	-	-	-	295	-	-	18	313
Other comprehensive income	-	-	-	-	82	-	-	82
Dividends on common stock ($1.88 per share)	-	-	-	(222)	-	-	-	(222)
Contribution from noncontrolling interest	-	-	-	-	-	-	22	22
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(6)	-	-	-	-	(6)
Stock issued, dividend reinvestment plan	0.3	1	10	-	-	-	-	11
Stock issued, share-based compensation, net of forfeitures	0.7	4	24	-	-	-	-	28
Stock-based compensation expense, net of tax	-	-	11	-	-	-	-	11
As of December 31, 2013	118.9	$ 595	$ 2,054	$ 1,063	$ (136)	$ (8)	$ 45	$ 3,613

(1) Includes correcting adjustments for the years ended December 31, 1998 through 2010. See Note 15 for additional information.

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

REVISED

	Years ended December 31,		
In millions	2013	2012	2011
Cash flows from operating activities			
Net income	$ 313	$ 275	$ 179
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	397	394	182
Change in derivative instrument assets and liabilities	66	72	(17)
Deferred income taxes	(16)	157	213
Gain on disposition of assets	(11)	-	-
Income from discontinued operations, net of tax	(5)	(1)	-
Changes in certain assets and liabilities			
Trade payables, other than energy marketing	89	49	(69)
Prepaid taxes	70	37	(88)
Accrued expenses	72	(24)	(77)
Inventories	41	43	157
Accrued natural gas costs	2	37	(3)
Receivables, other than energy marketing	(74)	12	43
Energy marketing receivables and trade payables, net	(54)	(44)	27
Other, net	70	(18)	(94)
Net cash flow provided by (used in) operating activities for discontinued operations	11	14	(2)
Net cash flow provided by operating activities	971	1,003	451
Cash flows from investing activities			
Acquisition of Nicor, net of cash acquired	-	-	(928)
Expenditures for property, plant and equipment	(731)	(775)	(427)
Acquisitions of assets	(154)	-	-
Disposition of assets	12	-	-
Other, net	8	(6)	-
Net cash flow (used in) provided by investing activities for discontinued operations	(11)	(5)	16
Net cash flow used in investing activities	(876)	(786)	(1,339)
Cash flows from financing activities			
Issuances of senior notes	494	-	1,289
Benefit, dividend reinvestment and stock purchase plan	33	21	19
Contribution from noncontrolling interest	22	-	-
Payment of senior notes	(225)	-	(300)
Dividends paid on common shares	(222)	(203)	(148)
Net (repayments) issuances of commercial paper	(206)	56	91
Distribution to noncontrolling interest	(17)	(14)	(16)
Payment of medium-term notes	-	(15)	-
Proceeds from termination of interest rate swap	-	17	-
Proceeds from term loan facility	-	-	150

Payments of term loan facility	-	-	(150)
Other, net	-	(17)	(2)
Net cash flow (used in) provided by financing activities	(121)	(155)	933
Net (decrease) increase in cash and cash equivalents - continuing operations	(26)	53	31
Net increase in cash and cash equivalents - discontinued operations	-	9	14
Cash and cash equivalents (including held for sale) at beginning of period	131	69	24
Cash and cash equivalents (including held for sale) at end of period	105	131	69
Less cash and cash equivalents held for sale at end of period	24	23	14
Cash and cash equivalents (excluding held for sale) at end of period	$ 81	$ 108	$ 55
Cash paid (received) during the period for			
Interest	$ 175	$ 174	$ 116
Income taxes	120	(37)	12
Non cash transactions			
Refinancing of gas facility revenue bonds	$ 200	$ -	$ -
Merger with Nicor, common stock issued 38.2 million shares	-	-	1,523

See Notes to Consolidated Financial Statements.

33

Notes to Consolidated Financial Statements

Note 1 - Organization and Basis of Presentation

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. Unless the context requires otherwise, references to “we,” “us,” “our,” the “company,” or “AGL Resources” mean consolidated AGL Resources Inc. and its subsidiaries.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2013 are prepared in accordance with GAAP and under the rules of the SEC. Our consolidated financial statements include our accounts, the accounts of our wholly owned subsidiaries, the accounts of our majority-owned and other controlled subsidiaries and the accounts of our variable interest entity for which we are the primary beneficiary. For unconsolidated entities that we do not control, but exercise significant influence over, we primarily use the equity method of accounting and our proportionate share of income or loss is recorded on the Consolidated Statements of Income. See Note 10 for additional information. We have eliminated intercompany profits and transactions in consolidation except for intercompany profits where recovery of such amounts are probable under the affiliates’ rate regulation process.

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

Revision of Previously-Issued Financial Statements We have revised our financial statements and other affected disclosures for items related to the recognition of revenues for certain of our regulatory infrastructure programs and the amortization of our intangible assets. We evaluated the cumulative impact of these items, together with other previously-identified adjustments for the same periods under the guidance in Accounting Standards Codification 250 Accounting Changes for Error Corrections (ASC 250) relating to SEC Staff Accounting Bulletin (SAB) No. 99, Materiality, and concluded that the revisions were not material, individually or in the aggregate, to any previously-issued quarterly or annual financial statements. We also evaluated the impact of revising these items through an adjustment to our financial statements for the quarter ended September 30, 2014 and concluded, based on the guidance within ASC 250 relating to SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, to revise our previously-issued financial statements to reflect the impact of these revisions. Our prior-period financial statements have been revised in this Amended Filing. See Note 15 for additional information.

On April 4, 2014 we entered into a definitive agreement to sell Tropical Shipping, which historically operated within our cargo shipping segment. We closed the sale of Tropical Shipping in September 2014. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position and the financial results of these businesses are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in the following notes, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified into our other segment. See Note 14 for additional information.

On December 9, 2011 we closed our merger with Nicor and created a combined company with increased scale and scope in the distribution, storage and transportation of natural gas. The businesses acquired in the merger are included in our consolidated financial statements for all of 2013 and 2012, and for 22 days of 2011.

Note 2 - Significant Accounting Policies and Methods of Application

Cash and Cash Equivalents

Our cash and cash equivalents primarily consist of cash on deposit, money market accounts and certificates of deposit held by domestic subsidiaries with original maturities of three months or less. As of December 31, 2013 and 2012, $24 million and $23 million, respectively, of cash and short and long-term investments in our Consolidated Statements of Financial Position held by Tropical Shipping are excluded from cash and cash equivalents as a result of the sale of that business and are included in assets held for sale. Prior to closing the sale, cash and short-term investments that were held in off-shore accounts were repatriated. See Note 12 and Note 14 for additional information on our income taxes on the cumulative foreign earnings for which no tax liability had previously been recorded.

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 upon settlement. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale services' counterparties are settled net, they are recorded on a gross basis in our 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 December 31, 2013 and 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 condition. If such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively impacted.

Wholesale services has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is generally concentrated in 20 of its counterparties and is measured by 30-day receivable exposure plus forward exposure. We evaluate the credit risk of our counterparties using an S&P equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's rating 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 equivalent to D/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 its financial ratios. The following table provides additional information about wholesale services' credit exposure at December 31, 2013, excluding $8 million of customer deposits.

Dollars in millions	Total (1)	# of top counterparties	Concentration risk %
Credit exposure	$274	20	51 %

(1) Our counterparties or the counterparties' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2013.

The weighted average credit rating is obtained by multiplying each counterparty's assigned internal rating by its credit exposure and then summing the individual results for all counterparties. The sum is divided by the aggregate total exposure and this numeric value is then converted to an S&P equivalent.

We have established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. government securities held by a trustee. When wholesale services is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty combined with a reasonable measure of our credit risk. Wholesale services also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Receivables and Allowance for Uncollectible Accounts

Our other trade receivables consist primarily of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and our accounts receivable are due within 30 days. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collection experience and other factors. For our remaining receivables, if we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the receivable balance to the amount we reasonably expect to collect. If circumstances change, our estimate of the recoverability of accounts receivable could change as well. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, customer deposits and general economic conditions. Customers' accounts are written off once we deem them to be uncollectible.

Nicor Gas Credit risk exposure at Nicor Gas is mitigated by a bad debt rider approved by the Illinois Commission. The bad debt rider provides for the recovery from (or refund to) customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and the benchmark bad debt expense used to establish its base rates for the respective year. See Note 3 for additional information on the bad debt rider.

Atlanta Gas Light Concentration of credit risk occurs at Atlanta Gas Light for amounts billed for services and other costs to its customers, which consist of 12 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. The functions of the retail sale of gas include the purchase and sale of natural gas, customer service, billings and collections. We obtain credit security support in an amount equal to no less than two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Inventories

For our regulated utilities, except Nicor Gas, our natural gas inventories and the inventories we hold for Marketers in Georgia are carried at cost on a WACOG basis. 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 11 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 the year that are restored prior to year end are charged to cost of goods sold at the estimated annual replacement cost. Inventory decrements that are not restored prior to year end are charged to cost of goods sold at the actual LIFO cost of the layers liquidated. Since the cost of gas, including inventory costs, is charged to customers without markup, subject to Illinois Commission review, LIFO liquidations have no impact on net income. At December 31, 2013, the Nicor Gas LIFO inventory balance was $168 million. Based on the average cost of gas purchased in December 2013, the estimated replacement cost of Nicor Gas' inventory at December 31, 2013 was $402 million, which exceeded the LIFO cost by $234 million.

Our retail operations, wholesale services, and midstream operations segments carry inventory at the lower of cost or market value, where cost is determined on a WACOG basis. For these segments, we evaluate the weighted average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, we record adjustments to reduce the weighted average cost of the natural gas inventory to market value. For the 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.

In millions	2013	2012	2011
Retail operations	$1	$3	$5
Wholesale services	8	19	31
Midstream operations	-	1	-

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. See Note 4 for additional fair value disclosures.

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. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

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

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

Level 3 Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management’s best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers’ needs. Transfers into and out of Level 3 reflect the liquidity at the relevant natural gas trading locations and dates, which affects the significance of unobservable inputs used in the valuation applied to natural gas derivatives. Our Level 3 assets, liabilities and any applicable transfers are primarily related to our pension and other retirement benefit plan assets as described in Note 3, Note 4 and Note 6. Transfers for retirement plan assets are described further in Note 4. We determine both transfers into and out of Level 3 using values at the end of the interim period in which the transfer occurred.

The authoritative guidance related to fair value measurements and disclosures also includes a two-step process to determine whether the market for a financial asset is inactive or a transaction is distressed. Currently, this authoritative guidance does not affect us, as our derivative instruments are traded in active markets.

Derivative Instruments

Our policy is to classify derivative cash flows and gains and losses within the same financial statement category as the hedged item, rather than by the nature of the instrument.

Fair Value Hierarchy Derivative assets and liabilities are classified in their entirety into the previously described fair value hierarchy levels based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The determination of the fair values incorporates various factors required under the guidance. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our own nonperformance risk on our liabilities. To mitigate the risk that a counterparty to a derivative instrument defaults on settlement or otherwise fails to perform under contractual terms, we have established procedures to monitor the creditworthiness of counterparties, seek guarantees or collateral backup in the form of cash or letters of credit and, in most instances, enter into netting arrangements. See Note 4 for additional fair value disclosures.

Netting of Cash Collateral and Derivative Assets and Liabilities under Master Netting Arrangements We maintain accounts with brokers to facilitate financial derivative transactions in support of our energy marketing and risk management activities. Based on the value of our positions in these accounts and the associated margin requirements, we may be required to deposit cash into these broker accounts.

We have elected to net derivative assets and liabilities under master netting arrangements on our Consolidated Statements of Financial Position. With that election, we are also required to offset cash collateral held in our broker accounts with the associated net fair value of the instruments in the accounts. See Note 4 for additional information about our cash collateral.

Natural Gas and Weather Derivative Instruments The fair value of the natural gas and weather derivative instruments that we use to manage exposures arising from changing natural gas prices and weather risk reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all of our derivative instruments. See Note 5 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. As previously noted, such derivative instruments are reported at fair value each reporting period in our Consolidated Statements of Financial Position. 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.

For our Illinois weather risk associated with Nicor Gas, we implemented a corporate weather hedging program in the second quarter of 2013 that utilizes OTC weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois. For January through April of 2014, we have purchased a put option that would partially offset lower operating margins resulting from lower customer usage in the event of warmer-than-normal weather, but would not be exercised in the event of colder-than-normal weather and, therefore, not offset higher margins if Heating Degree Days for the period are at normal or colder-than-normal levels. We will continue to use available methods to mitigate our exposure to weather in Illinois for future periods.

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, which occurs 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 our Consolidated Statements of Income in the period in which it occurs. We have not designated the remainder of our derivative instruments as hedges for accounting purposes and, accordingly, we record changes in the fair values of such instruments within cost of goods sold in our Consolidated Statements of Income 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 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 will ultimately 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 in our Consolidated Statements of Financial Position, with changes in fair value recorded in operating revenues in our Consolidated Statements of Income 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 we recognize these demand charges and payments in our Consolidated Statements of Income in the period they are incurred. This difference in accounting methods can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the dates the transactions were consummated.

Debt We estimate the fair value of debt using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile. In determining the market interest yield curve, we consider our currently assigned ratings for unsecured debt and the secured rating for the Nicor Gas first mortgage bonds.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2013 and 2012 is provided in the following table.

In millions	2013	2012
Transportation and distribution (1)	$8,371	$7,979
Storage facilities	1,170	1,149
Other	854	820
Construction work in progress	543	371
Total PP&E, gross	10,938	10,319
Less accumulated depreciation (1)	2,295	2,114
Total PP&E, net (1)	$8,643	$8,205

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

Distribution Operations Our natural gas utilities' PP&E consists of property and equipment that is currently in use, being held for future use and currently under construction. We report PP&E at its original cost, which includes:

- material and labor;
- contractor costs;
- construction overhead costs;
- AFUDC; and,
- Nicor Gas' pad gas - the portion considered to be non-recoverable is recorded as depreciable PP&E, while the portion considered to be recoverable is recorded as non-depreciable PP&E.

We recognize no gains or losses on depreciable utility property that is retired or otherwise disposed, as required under the composite depreciation method. Such gains and losses are ultimately refunded to, or recovered from, customers through future rate adjustments. Our natural gas utilities also hold property, primarily land; this is not presently used and useful in utility operations and is not included in rate base. Upon sale, any gain or loss is recognized in other income.

Retail Operations, Wholesale Services, Midstream Operations and Other PP&E includes property that is in use and under construction, and we report it at cost. We record a gain or loss within operation and maintenance expense for retired or otherwise disposed-of property. Natural gas in salt-dome storage at Jefferson Island and Golden Triangle that is retained as pad gas is classified as non-depreciable PP&E and is carried at cost. Central Valley has two types of pad gas in its depleted reservoir storage facility. The first is non-depreciable PP&E, which is carried at cost, and the second is non-recoverable, over which we have no contractual ownership.

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. More information on our rates used and the rate method is provided in the following table.

	2013		2012		2011	
Atlanta Gas Light (1)	2.6	%	2.6	%	2.6	%
Chattanooga Gas (1)	2.5	%	2.5	%	2.5	%
Elizabethtown Gas (2)	2.4	%	2.4	%	2.5	%
Elkton Gas (2)	2.4	%	2.4	%	2.4	%
Florida City Gas (2)	3.8	%	3.9	%	3.9	%
Nicor Gas (2) (3)	3.1	%	4.1	%	4.1	%
Virginia Natural Gas (1)	2.5	%	2.5	%	2.5	%

(1) Average composite straight-line depreciation rates for depreciable property, excluding transportation equipment, which may be depreciated in excess of useful life and recovered in rates.

(2) Composite straight-line depreciation rates.

(3) On October 23, 2013, the Illinois Commission approved a composite depreciation rate of 3.07%. The depreciation rate was effective as of August 30, 2013, the date the depreciation study was filed, and had the effect of reducing our 2013 depreciation expense by $19 million.

For our non-regulated segments, we compute depreciation expense on a straight-line basis over the following estimated useful lives of the assets.

In years	Estimated useful life

Transportation equipment	5 - 10
Storage caverns	40 - 60
Other	up to 40

AFUDC and Capitalized Interest

Atlanta Gas Light, Nicor Gas, Chattanooga Gas and Elizabethtown Gas are authorized by applicable state regulatory agencies or legislatures to capitalize the cost of debt and equity funds as part of the cost of PP&E construction projects in our Consolidated Statements of Financial Position. More information on our authorized or actual AFUDC rates is provided in the following table.

	2013		2012		2011	
Atlanta Gas Light	8.10	%	8.10	%	8.10	%
Nicor Gas (1)	0.31	%	0.36	%	0.18	%
Chattanooga Gas	7.41	%	7.41	%	7.41	%
Elizabethtown Gas (1)	0.41	%	0.51	%	0.53	%
AFUDC (in millions) (2)	$18		$8		$6	

(1) Variable rate is determined by FERC method of AFUDC accounting.
(2) Amount recorded in the Consolidated Statements of Income.

The capital expenditures of our other three utilities do not qualify for AFUDC treatment.

Asset Retirement Obligations

We record a liability at fair value for an asset retirement obligation (ARO) when a legal obligation to retire the asset has been incurred, with an offsetting increase to the carrying value of the related asset. Accretion of the ARO due to the passage of time is recorded as an operating expense. We have recorded an ARO of $3 million at December 31, 2013 and 2012 principally for our storage facilities. For our distribution PP&E, we cannot reasonably estimate the fair value of this obligation because we have determined that we have insufficient internal or industry information to reasonably estimate the potential settlement dates or costs.

Impairment of Assets

Our goodwill is not amortized, but is subject to an annual impairment test. Our other long-lived assets, including our finite-lived intangible assets, require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of the recoverability of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors.

Goodwill We perform an annual goodwill impairment test on our reporting units that contain goodwill during the fourth quarter of each year, or more frequently if impairment indicators arise. These indicators include, but are not limited to, a significant change in operating performance, the business climate, legal or regulatory factors, or a planned sale or disposition of a significant portion of the business. To estimate the fair value of our reporting units, we use two generally accepted valuation approaches, the income approach and the market approach, using assumptions consistent with a market participant’s perspective.

Under the income approach, fair value is estimated based on the present value of estimated future cash flows discounted at an appropriate risk-free rate that takes into consideration the time value of money, inflation and the risks inherent in ownership of the business being valued. The cash flow estimates contain a degree of uncertainty, and changes in the projected cash flows could significantly increase or decrease the estimated fair value of a reporting unit. For the regulated reporting units, a fair recovery of, and return on, costs prudently incurred to serve customers is assumed. An unfavorable outcome in a rate case could cause the fair value of these reporting units to decrease. Key assumptions used in the income approach include the return on equity for the regulated reporting units, long-term growth rates used to determine terminal values 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 is based on a combination of historical and forecasted statistics for real gross domestic product and personal income for each utility service area. The estimated rates we will charge to customers for capacity in the storage caverns were based on internal and external rate forecasts.

Under the market approach, fair value is estimated by applying multiples to forecasted cash flows. This method uses metrics from similar publicly-traded companies in the same industry, when available, to determine how much a knowledgeable investor in the marketplace would be willing to pay for an investment in a similar company.

We weight the results of the two valuation approaches to estimate the fair value of each reporting unit. Our goodwill impairment testing also develops a baseline test and performs a sensitivity analysis to calculate a reasonable valuation range. The sensitivities are derived by altering those assumptions that are subjective in nature and inherent to a discounted cash flows calculation.

The significant assumptions that drive the estimated values of our reporting units are projected cash flows, discount rates, growth rates, weighted average cost of capital (WACC) and market multiples. Due to the subjectivity of these assumptions, we cannot provide assurance that future analyses will not result in impairment, as a future impairment depends on market and economic factors affecting fair value. Our annual goodwill impairment analysis in the fourth quarter of 2013 indicated that the estimated fair values of all but one of our reporting units with goodwill were in excess of the carrying values by approximately 20% to almost 500%, and were not at risk of failing step one of the impairment test.

Within our midstream operations segment, the estimated fair value of our storage and fuels reporting unit with $14 million of goodwill, exceeded its carrying value by less than 5% and is at risk of failing the step one test. The discounted cash flow model used in the goodwill impairment test for this reporting unit assumed discrete period revenue growth through fiscal 2021 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year off of which we estimated the terminal value. In the terminal year we assumed a long-term earnings growth rate of 2.5% that we believe is appropriate given the current economic and industry specific expectations. As of the valuation date, we utilized a WACC of 7.0%, which we believe is appropriate as it reflects the relative risk, the time value of money, and is consistent with the peer group of this reporting unit as well as the discount rate that was utilized in our 2012 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next eight years. Should this growth not occur, this reporting unit may fail step one of a goodwill impairment test in a future period. Along with any reductions to our cash flow forecast, changes in other key assumptions used in our 2013 annual impairment analysis may result in the requirement to proceed to step two of the goodwill impairment test in future periods.

We will continue to monitor this reporting unit for impairment and note that continued declines in capacity or subscription rates, declines for a sustained period at the current market rates or other changes to the key assumptions and factors used in this analysis may result in a future 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 on the basis of undiscounted cash flows over their remaining useful lives.

Changes in the amount of goodwill for the twelve months ended December 31, 2013 and 2012 are provided below.

In millions	Distribution Operations	Retail Operations	Wholesale Services	Midstream Operations	Other	Consolidated (1)
Goodwill - December 31, 2011	$1,586	$124	$2	$16	$8	$ 1,736
Adjustments to initial Nicor purchase price allocation and other	54	(2)	(2)	(2)	(8)	40
Goodwill - December 31, 2012	1,640	122	-	14	-	1,776
2013 acquisitions	-	51	-	-	-	51
Goodwill - December 31, 2013	$1,640	$173	$-	$14	$-	$ 1,827

(1) Excludes goodwill at Tropical Shipping now classified as held for sale. See Note 14 for additional information.

Long-Lived Assets We depreciate or amortize our long-lived assets and other intangible assets over their useful lives. Currently, we have no significant indefinite-lived intangible assets. These long-lived assets and other intangible assets are reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through expected future cash flows. An impairment is indicated if the carrying amount of the long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no long-lived asset impairments in 2013, with the exception of Sawgrass Storage, for which we recorded an $8 million loss.

Intangible Assets Our intangible assets are presented in the following table and represent the estimated fair value at the date of acquisition of the acquired intangible assets in our businesses. As indicated previously, we perform an impairment review when impairment indicators are present. If present, we first determine whether the carrying amount of the asset is recoverable through the undiscounted future cash flows expected from the asset. If the carrying amount is not recoverable, we measure the impairment loss, if any, as the amount by which the carrying amount of the asset exceeds its fair value. The increase in our intangible assets of $91 million as of December 31, 2013 compared to the prior year was the result of two acquisitions within the retail operations segment. For more information, see "Acquisitions" in Note 2.

	Weighted average amortization period	December 31, 2013 (1)			December 31, 2012 (1)		
In millions	(in years)	Gross	Accumulated amortization	Net	Gross	Accumulated amortization	Net
Customer relationships							
Retail operations	13	$130	$ (25)	$105	$53	$ (11)	$42
Trade names							

Retail operations	13	45	(5)	40	30	(2)	28
Wholesale services	-	-	-	-	1	-	1
Total		$175	$ (30)	$145	$84	$ (13)	$71

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

We amortize these intangible assets in a manner in which the economic benefits are consumed utilizing the undiscounted cash flows which were used in the determination of their fair values. Amortization expense was $18 million in 2013, $13 million in 2012 and $0 in 2011. Amortization expense for the next five years is estimated to be as follows:

In millions	Amortization Expense (1)
2014	$ 20
2015	18
2016	16
2017	15
2018	13

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

41

Accounting for Retirement Benefit Plans

We recognize the funded status of our plans as an asset or a liability on our Consolidated Statements of Financial Position, measuring the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We recognize, as a component of OCI, the changes in funded status that occurred during the year that are not yet recognized as part of net periodic benefit cost. Because substantially all of its retirement costs are recoverable through base rates, Nicor Gas generally defers any charge or credit to comprehensive income to a regulatory asset or liability until the period in which the costs are included in base rates, in accordance with the authoritative guidance for rate-regulated entities. The assets of our retirement plans are measured at fair value within the funded status and are classified in the fair value hierarchy in their entirety based on the lowest level of input that is significant to the fair value measurement.

In determining net periodic benefit cost, the expected return on plan assets component is determined by applying our expected return on assets to a calculated asset value, rather than to the fair value of the assets as of the end of the previous fiscal year. For more information, see Note 6. In addition, we have elected to amortize gains and losses caused by actual experience that differs from our assumptions into subsequent periods. The amount to be amortized is the amount of the cumulative gain or loss as of the beginning of the year, excluding those gains and losses not yet reflected in the calculated value, that exceeds 10 percent of the greater of the benefit obligation or the calculated asset value; and the amortization period is the average remaining service period of active employees.

Taxes

Income Taxes The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal difference between net income and taxable income relates to the timing of deductions, primarily due to the benefits of tax depreciation since we generally depreciate assets for tax purposes over a shorter period of time than for book purposes. The determination of our provision for income taxes requires significant judgment, the use of estimates, and the interpretation and application of complex tax laws. Significant judgment is required in assessing the timing and amounts of deductible and taxable items. We report the tax effects of depreciation and other temporary differences as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position.

We have current and deferred income taxes in our Consolidated Statements of Income. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense is generally equal to the changes in the deferred income tax liability and regulatory tax liability during the year. We have recorded current deferred income taxes of $43 million (net of a valuation allowance of $8 million) as of December 31, 2013 and $4 million as of December 31, 2012 within other current assets in our Consolidated Statements of Financial Position.

Accumulated Deferred Income Tax Assets and Liabilities As noted above, we report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure these deferred income tax assets and liabilities using enacted income tax rates.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability. We had $80 million of such cash and short-term investments on our Consolidated Statements of Financial Position as of December 31, 2013 and 2012. As of December 31, 2013, we would be required to record a deferred tax liability of $31 million if we no longer asserted indefinite reinvestment of undistributed foreign earnings.

Income Tax Benefits The authoritative guidance related to income taxes requires us to determine whether tax benefits claimed or expected to be claimed on our tax return should be recorded in our consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement.

Uncertain Tax Positions We recognize accrued interest related to uncertain tax positions in interest expense and penalties in operating expense in our Consolidated Statements of Income.

Tax Collections We do not collect income taxes from our customers on behalf of governmental authorities. However, we do collect and remit various other taxes on behalf of various governmental authorities. We record these amounts in our Consolidated Statements of Financial Position. In other instances, we are allowed to recover from customers other taxes that are imposed upon us. We record such taxes as operating expenses and record the corresponding customer charges as operating revenues.

Revenues

Distribution operations We record revenues when goods or services are provided to customers. Those revenues are based on rates approved by the state regulatory commissions of our utilities.

As required by the Georgia Commission, Atlanta Gas Light bills Marketers in equal monthly installments for each residential, commercial and industrial end-use customer's distribution costs. Additionally, as required by the Georgia Commission, Atlanta Gas Light bills Marketers for capacity costs utilizing a seasonal rate design for the calculation of each residential end-use customer's annual straight-fixed-variable (SFV) charge, which reflects the historic volumetric usage pattern for the entire residential class. Generally, this seasonal rate design results in billing the Marketers a higher capacity charge in the winter months and a lower charge in the summer months, which impacts our operating cash flows. However, this seasonal billing requirement does not impact our revenues, which are recognized on a straight-line basis because the associated rate mechanism ensures that we ultimately collect the full annual amount of the SFV charges.

All of our utilities, with the exception of Atlanta Gas Light, have rate structures that include volumetric rate designs which allow recovery of certain costs based on gas usage. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. Additionally, revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the last bill date to the end of the accounting period. These are included in the Consolidated Statements of Financial Position as unbilled revenue. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas contain WNAs that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The purpose of a WNA is to mitigate the effect of weather on customer bills by reducing bills when winter weather is colder-than-normal and increasing bills when weather is warmer-than-normal. In addition, the tariffs for Virginia Natural Gas, Chattanooga Gas and Elkton Gas contain revenue normalization mechanisms that mitigate the impact of conservation and declining customer usage.

Revenue Taxes We charge customers for gas revenue and gas use taxes imposed on us and remit amounts owed to various governmental authorities. Our policy for gas revenue taxes is to record the amounts charged to customers, which for some taxes includes a small administrative fee, as operating revenues, and to record the related taxes incurred as operating expenses in our Consolidated Statements of Income. Our policy for gas use taxes is to exclude these taxes from revenue and expense, aside from a small administrative fee that is included in operating revenues. As a result, the amount recorded in operating revenues will exceed the amount recorded in operating expenses by the amount of administrative fees that are retained by the Company. Revenue taxes included in operating expenses were $110 million in 2013, $85 million in 2012 and $9 million in 2011.

Retail operations Revenues from natural gas sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recognized for estimated deliveries of gas not yet billed to these customers, from the most recent meter reading date to the end of the accounting period. The related receivables are included in the Consolidated Statements of Financial Position as unbilled revenue. For other commercial and industrial customers and for all wholesale customers, revenues are based on actual deliveries during the period.

We recognize revenues on 12-month utility-bill management contracts as the lesser of cumulative earned or cumulative billed amounts. We recognize revenues for warranty and repair contracts on a straight-line basis over the contract term. Revenues for maintenance services are recognized at the time such services are performed.

Wholesale services We record wholesale services' revenues when services are provided to customers. Profits from sales between segments are eliminated in the other segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under authoritative guidance related to derivatives and hedging are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are required to be presented net in revenue.

Midstream operations We record operating revenues for storage and transportation services in the period in which volumes are transported and storage services are provided. The majority of our storage services are covered under medium to long-term contracts at fixed market-based rates. We recognize our park and loan revenues ratably over the life of the contract.

Cost of goods sold

Distribution operations Excluding Atlanta Gas Light, which does not sell natural gas to end-use customers, we charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the state regulatory agencies. Under these mechanisms, all prudently incurred natural gas costs are passed through to customers without markup, subject to regulatory review. In accordance with the authoritative guidance for rate-regulated entities, we defer or accrue (that is, include as an asset or liability in the Consolidated Statements of Financial Position and exclude from, or include in, the Consolidated Statements of Income, respectively) the difference between the actual cost of goods sold and the amount of commodity revenue earned in a given period, such that no operating margin is recognized related to these costs. The deferred or accrued amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate. Deferred natural gas costs are reflected as regulatory assets and accrued natural gas costs are reflected as regulatory liabilities. For more information, see Note 3.

Retail operations Our retail operations customers are charged for actual or estimated natural gas consumed. Within our cost of goods sold, we also include costs of fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and gains and losses associated with certain derivatives. Costs to service our warranty and repair contract claims and costs associated with the installation of heating and cooling equipment are recorded to cost of goods sold.

Operating leases

We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with authoritative guidance related to leases. This accounting treatment does not affect the future annual operating lease cash obligations. For more information, see Note 11.

Other income

Our other income is detailed in the following table. For more information on our equity investment income, see Note 10.

In millions	2013	2012	2011
AFUDC - equity	$12	$6	$4
Equity investment income	3	13	1
Other, net	1	5	2
Total other income	$16	$24	$7

Earnings Per Common Share

We compute basic earnings per common share attributable to AGL Resources Inc. common shareholders by dividing our net income attributable to AGL Resources Inc. by the daily weighted average number of common shares outstanding. Diluted earnings per common share attributable to AGL Resources Inc. common shareholders reflect the potential reduction in earnings per common share attributable to AGL Resources Inc. common shareholders that occurs when potentially dilutive common shares are added to common shares outstanding. The increase in weighted average shares in 2012 compared to 2011 is primarily due to the issuance of 38.2 million shares in connection with the Nicor merger on December 9, 2011.

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.

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.

In millions (except per share amounts)	2013 (1)	2012 (1)	2011 (1)
Income from continuing operations (2)	$290	$259	$165
Income from discontinued operations, net of tax	5	1	-
Net income attributable to AGL Resources Inc.	$295	$260	$165
Denominator:			

Basic weighted average number of shares outstanding (3)	117.9	117.0	80.4
Effect of dilutive securities	0.4	0.5	0.5
Diluted weighted average number of shares outstanding (4)	118.3	117.5	80.9
Basic earnings per share			
Continuing operations	$2.46	$2.21	$2.05
Discontinued operations	0.04	0.01	-
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$2.50	$2.22	$2.05
Diluted earnings per share (3)			
Continuing operations	$2.45	$2.20	$2.04
Discontinued operations	0.04	0.01	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$2.49	$2.21	$2.04

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

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

(3) Daily weighted average shares outstanding.

(4) There were no outstanding stock options excluded from the computation of diluted earnings per common share attributable to AGL Resources Inc. for any of the periods presented because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price.

Acquisitions

On January 31, 2013, our retail operations segment acquired approximately 500,000 service contracts and certain other assets from NiSource Inc. for $122 million. These service contracts provide home warranty protection solutions and energy efficiency leasing solutions to residential and small business utility customers and complement the retail business acquired in the Nicor merger. Intangible assets related to this acquisition are primarily customer relationships of $46 million and trade names of $16 million. The amortization periods are estimated to be 14 years for customer relationships and 10 years for trade names. The final allocation of the purchase price to the fair value of assets acquired and liabilities assumed is presented in the following table:

In millions	
Current assets	$3
PP&E	12
Goodwill	51
Intangible assets	62
Current liabilities	(6)
Total purchase price	$122

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 amortized over 15 years.

On December 9, 2011, we completed our $2.5 billion merger with Nicor that created a combined company with increased scale and scope in the distribution, storage and transportation of natural gas. The effects of Nicor's results of operations and financial condition are reflected for the twelve months ended December 31, 2013 and 2012, while our 2011 results include activity from December 10, 2011 through December 31, 2011. This merger resulted in:

- The issuance of 38.2 million shares of AGL Resources common stock
- Increased revenues in 2012 of $2,063 million
- Increased net income in 2012 of $70 million
- An increase to PP&E of $3,192 million
- An increase to goodwill and other intangible assets of $1,423 million and $103 million, respectively

Sale of Compass Energy

On May 1, 2013 we sold Compass Energy, a non-regulated retail natural gas business supplying commercial and industrial customers, within 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 that was recognized during 2013. The remaining $5 million of contingent cash consideration will be determined and would be received from the buyer annually over a five-year earn out period based upon the financial performance of Compass Energy. We have a five year agreement to supply natural gas to our former customers. Accordingly, as a result of our continued involvement, the sale of Compass Energy did not meet the criteria for treatment as a discontinued operation.

Non-Wholly Owned Entities

We hold ownership interests in a number of business ventures with varying ownership structures. We evaluate all of our partnership interests and other variable interests to determine if each entity is a variable interest entity (VIE), as defined in the authoritative accounting guidance. If a venture is a VIE for which we are the primary beneficiary, we consolidate the assets, liabilities and results of operations of the entity. We reassess our conclusion as to whether an entity is a VIE upon certain occurrences, which are deemed reconsideration events under the guidance. We have concluded that the only venture that we are required to consolidate as a VIE, as we are the primary beneficiary, is SouthStar. On our Consolidated Statements of Financial Position, we recognize Piedmont's share of the non-wholly owned entity as a separate component of equity entitled "noncontrolling interest." Piedmont's share of current operations is reflected in "net income attributable to the noncontrolling interest" on our Consolidated Statements of Income. The consolidation of SouthStar has no effect on our calculation of basic or diluted earnings per common share amounts, which are based upon net income attributable to AGL Resources Inc.

For entities that are not determined to be VIEs, we evaluate whether we have control or significant influence over the investee to determine the appropriate consolidation and presentation. Generally, entities under our control are consolidated, and entities over which we can exert significant influence, but do not control, are accounted for under the equity method of accounting. However, we also invest in partnerships and limited liability companies that maintain separate ownership accounts. All such investments are required to be accounted for under the equity method unless our interest is so minor that there is virtually no influence over operating and financial policies, as are all investments in joint ventures.

Investments accounted for under the equity method are included in long-term investments on our Consolidated Statements of Financial Position, and the equity income is recorded within other income on our Consolidated Statements of Income and was immaterial for all periods presented. For additional information, see Note 10.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our rate-regulated subsidiaries, regulatory infrastructure program accruals, uncollectible accounts and other allowances for contingent losses, goodwill and 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.

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 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 consolidated financial statements. See Note 9 for additional disclosures relating to accumulated other comprehensive income.

Note 3 – Regulated Operations

We account for the financial effects of regulation in accordance with authoritative guidance related to regulated entities whose rates are designed to recover the costs of providing service. In accordance with this guidance, incurred costs and estimated future expenditures that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs or expenditures will be recovered in rates in the future. Similarly, we recognize regulatory liabilities when it is probable that regulators will require customer refunds through future rates or when revenue is collected from customers for estimated expenditures that have not yet been incurred. Generally, regulatory assets are amortized into expense and regulatory liabilities are amortized into income over the period authorized by the regulatory commissions. Our regulatory assets and liabilities as of December 31, are summarized in the following table.

In millions	2013 (1)	2012 (1)
Regulatory assets		
Recoverable ERC	$45	$38
Recoverable pension and retiree welfare benefit costs	9	19
Other	60	41
Total regulatory assets - current	114	98
Recoverable ERC	433	438
Recoverable pension and retiree welfare benefit costs	99	196
Recoverable regulatory infrastructure program costs	55	162
Long-term debt fair value adjustment	82	90
Other	36	53
Total regulatory assets - long-term	705	939
Total regulatory assets	$819	$1,037
Regulatory liabilities		
Accrued natural gas costs	$92	$93
Bad debt over collection	41	37
Accumulated removal costs	27	16
Other	23	15
Total regulatory liabilities - current	183	161
Accumulated removal costs	1,445	1,393
Regulatory income tax liability	27	27
Unamortized investment tax credit	26	29
Bad debt over collection	17	17
Other	3	11
Total regulatory liabilities - long-term	1,518	1,477
Total regulatory liabilities	$1,701	$1,638

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

Our regulatory assets are probable of recovery. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all of our regulatory assets recoverable through base rates are subject to review by the respective state regulatory commission during future rate proceedings. We are not aware of 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. Additionally, while some regulatory liabilities would be written off, others would continue to be recorded as liabilities, but not as regulatory liabilities.

Although the natural gas distribution industry is competing with alternative fuels, primarily electricity, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under the guidance remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider or proceeding. The regulatory liabilities that do not represent revenue collected from customers for expenditures that have not yet been incurred are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base used to periodically set base rates.

The majority of our regulatory assets and liabilities listed in the preceding table are included in base rates except for the regulatory infrastructure program costs, ERC, bad debt, natural gas and energy efficiency costs, which are recovered through specific rate riders on a dollar-for-dollar basis. The rate riders that authorize the recovery of regulatory infrastructure program costs and natural gas costs include both a recovery of cost and a return on investment during the recovery period. Nicor Gas' rate riders for environmental costs and energy efficiency costs provide a return of investment and expense including short-term interest on reconciliation balances. However, there is no interest associated with the under or over collections of bad debt expense.

Nicor Gas' pension and retiree welfare benefit costs have historically been considered in rate proceedings in the same period they are accrued under GAAP. As a regulated utility, Nicor Gas expects to continue rate recovery of the eligible costs of these defined benefit retirement plans and, accordingly, associated changes in the funded status of Nicor Gas' plans have been deferred as a regulatory asset or liability until recognized in net income, instead of being recognized in OCI. The Illinois Commission presently does not allow Nicor Gas the opportunity to earn a return on its recoverable retirement benefit costs. Such costs are expected to be recovered over a period of 11 years. The regulatory assets related to debt are also not included in rate base, but the costs are recovered over the term of the debt through the authorized rate of return component of base rates.

Unrecognized Ratemaking Amounts We have authorized unrecognized ratemaking amounts that are not reflected within our Consolidated Statements of Financial Position as indicated in the following table. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs. These amounts will be recognized as revenues in our financial statements in the periods they are collected in rates from our customers. For additional information, see Note 15.

In millions	
December 31, 2013	$93
December 31, 2012	$64

As of December 31, 2013, this amount includes $80 million related to Atlanta Gas Light, $12 million at Virginia Natural Gas and $1 million at Elizabethtown Gas.

Environmental Remediation Costs We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. Our ERC liabilities are estimates of future remediation costs for investigation and cleanup of our 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, on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, legal expenses or other costs for which we may be held liable but for which we cannot reasonably estimate an amount.

Our accrued ERC costs are not regulatory liabilities; however they are deferred as a corresponding regulatory asset until the costs are recovered from customers. These recoverable ERC assets are a combination of accrued ERC liabilities and recoverable cash expenditures for investigation and cleanup costs. We primarily recover these deferred costs through three rate riders that authorize dollar-for-dollar recovery. We expect to collect $45 million in revenues over the next 12 months, which is reflected as a current regulatory asset. We recovered $24 million in 2013, $13 million in 2012 and $5 million in 2011 from our ERC rate riders. The following table provides more information on the costs related to remediation of our former operating sites.

In millions	# of sites	Probabilistic model cost estimates (2)	Engineering estimates (2)	Amount recorded	Expected costs over next 12 months	Cost recovery period
Illinois (1)	24	$ 209 - $458	$ 42	$ 251	$ 38	As incurred (3)
New Jersey	6	139 - 233	6	145	18	7 years (3)

Georgia and Florida	13		28 - 112		8		40		7	5 years
North Carolina	1		n/a		11		11		7	No recovery
Total	44	$	376 - $803	$	67	$	447	$	70	

(1) Nicor Gas and Commonwealth Edison Company are parties to an agreement to cooperate equally in cleaning up residue at 23 sites.

(2) Material cleanups have not been completed for 26 sites. Therefore precise estimates are not available for future cleanup costs and considerable variability remains in future cost estimates.

(3) Includes recovery of carrying costs on unrecovered expenditures.

Bad Debt Rider Nicor Gas' bad debt rider provides for the recovery from, or refund to, customers of the difference between Nicor Gas' actual bad debt experience on an annual basis and a benchmark bad debt expense of $63 million, as determined by the Illinois Commission in February 2010. The over recovery is recorded as an increase to operating expenses on our Consolidated Statements of Income and a regulatory liability on our Consolidated Statements of Financial Position until refunded to customers. In the period refunded, operating expenses are reduced and the regulatory liability is reversed. The actual bad debt experience and resulting refunds are shown in the following table.

	Bad debt	Total	Amount refunded in		Amount to be refunded in	
In millions	experience	refund	2012	2013	2014	2015
2013	$21	$42	$-	$-	$25	$17
2012	23	40	-	24	16	-
2011	31	32	19	13	-	-

Accumulated Removal Costs In accordance with regulatory treatment, our depreciation rates are comprised of two cost components - historical cost and the estimated cost of removal, net of estimated salvage, of certain regulated properties. We collect these costs in base rates through straight-line depreciation expense, with a corresponding credit to accumulated depreciation. Because the accumulated estimated removal costs are not a generally accepted component of depreciation, but meet the requirements of authoritative guidance related to regulated operations, we have reclassified them from accumulated depreciation to the accumulated removal cost regulatory liability in our Consolidated Statements of Financial Position. In the rate setting process, the liability for these accumulated removal costs is treated as a reduction to the net rate base upon which our regulated utilities have the opportunity to earn their allowed rate of return.

Regulatory Infrastructure Programs We have infrastructure improvement programs at several of our utilities. Descriptions of these are as follows.

Atlanta Gas Light Our STRIDE program is comprised of the pipeline replacement program, the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and a new component, the Integrated Vintage Plastic Replacement Program (i-VPR). In 1998, the pipeline replacement program was ordered by the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Georgia Commission) and required Atlanta Gas Light to replace all bare steel and cast iron pipe in its system by December 2013.

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.

The purpose of the i-VPR program is to 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. On August 6, 2013, the Georgia Commission approved 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 through a monthly rider surcharge of $0.48 per customer through December 2014. This will be increased to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016 and will continue through 2025.

The orders for the STRIDE programs provide for recovery of all prudent costs incurred in the performance of the program. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the programs net of any cost savings from the programs. All such amounts will be recovered through a combination of straight-fixed-variable rates and a STRIDE revenue rider surcharge. The regulatory asset represents recoverable incurred costs related to the programs that will be collected in future rates charged to customers through the rate riders. The future expected costs to be recovered through rates related to allowed, but not incurred costs, are recognized in an unrecognized ratemaking amount that is not reflected within our Consolidated Statements of Financial Position. This allowed cost consists primarily of the equity return on the capital investment under the program.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the STRIDE programs over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Elizabethtown Gas In 2009, the New Jersey BPU approved the enhanced infrastructure program for Elizabethtown Gas, which was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. In May 2011, the New Jersey BPU approved Elizabethtown Gas' request to spend an additional $40 million under this program before the end of 2012. Costs associated with the investment in this program are recovered through periodic adjustments to base rates that are approved by the New Jersey BPU. In August 2013, the New Jersey BPU approved the recovery of investments under this program through a permanent adjustment to base rates.

Additionally, in August 2013, we received approval from the New Jersey BPU for an extension of the accelerated infrastructure replacement program that we filed in July 2012. The approval allows for infrastructure investment of $115 million over four years, effective as of September 1, 2013. Carrying charges on the additional capital expenditures will be deferred at a weighted average cost for capital of 6.65%, of which 4.27% will be within an unrecognized ratemaking amount and will be recognized in future periods when recovered through rates. Unlike the previous program, there will be no adjustment to base rates for the investments under the extended program until Elizabethtown Gas files its next rate case. We agreed to file a general rate case by September 2016.

On September 3, 2013, Elizabethtown Gas filed for a Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program that will improve our distribution system's resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas 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 On June 25, 2012, the Virginia Commission approved SAVE, an accelerated infrastructure replacement program, which is expected to be completed over a five-year period. The program permits a maximum 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 program costs through a rate rider that was effective August 1, 2012. On May 1, 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 on July 23, 2013 and became effective as of August 1, 2013. On May 1, 2013, the Virginia Commission approved our CARE plan, which includes a limited set of conservation programs and measures at a cost of $2 million over a three-year period. The CARE plan became effective June 1, 2013.

Investment Tax Credits Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our Consolidated Statements of Financial Position. These investment tax credits are being amortized over the estimated lives of the related properties as credits to income tax expense.

Regulatory Income Tax Liability For our regulated utilities, we also measure deferred income tax assets and liabilities using enacted income tax rates. Thus, when the statutory income tax rate declines before a temporary difference has fully reversed, the deferred income tax liability must be reduced to reflect the newly enacted income tax rates. However, the amount of the reduction is transferred to our regulatory income tax liability, which we are amortizing over the lives of the related properties as the temporary differences reverse over approximately 30 years.

Other Regulatory Assets and Liabilities Our recoverable pension and retiree welfare benefit plan costs for our utilities other than Nicor Gas are expected to be recovered through base rates over the next 2 to 21 years, based on the remaining recovery periods as designated by the applicable state regulatory commissions. This category also includes recoverable seasonal rates, which reflect the difference between the recognition of a portion of Atlanta Gas Light's residential base rates revenues on a straight-line basis as compared to the collection of the revenues over a seasonal pattern. These amounts are fully recoverable through base rates within one year.

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 five-month timeframe, or by March 1, 2014, as established by statute for electric utilities. The new plan must be implemented by June 1, 2014.

50

Note 4 - Fair Value Measurements

Retirement benefit plans

The allocations of the AGL Resources Inc. Retirement Plan (AGL Plan), the Employees' Retirement Plan of NUI Corporation (NUI Plan), and the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) were approximately 74% equity and 26% fixed income at December 31, 2013. The plans' investment policies provide for some variation in these targets. The actual asset allocations of our retirement plans are presented in the following table by Level within the fair value hierarchy.

	December 31, 2013									
	Pension plans (1)					Welfare plans				
In millions	Level 1	Level 2	Level 3	Total	% of total	Level 1	Level 2	Level 3	Total	% of total
Cash	$3	$1	$-	$4	- %	$1	$-	$-	$1	1 %
Equity securities:										
U.S. large cap (2)	93	205	-	298	33 %	-	52	-	52	62 %
U.S. small cap (2)	72	29	-	101	11 %	-	-	-	-	- %
International companies (3)	-	139	-	139	15 %	-	14	-	14	17 %
Emerging markets (4)	-	34	-	34	4 %	-	-	-	-	- %
Fixed income securities:										
Corporate bonds (5)	-	207	-	207	23 %	-	17	-	17	20 %
Other (or gov't/muni bonds)	-	29	-	29	3 %	-	-	-	-	- %
Other types of investments:										
Global hedged equity (6)	-	-	43	43	5 %	-	-	-	-	- %
Absolute return (7)	-	-	39	39	4 %	-	-	-	-	- %
Private capital (8)	-	-	22	22	2 %	-	-	-	-	- %
Total assets at fair value	$168	$644	$104	$916	100 %	$1	$83	$-	$84	100 %
% of fair value hierarchy	19 %	70 %	11 %	100 %		1 %	99 %	- %	100 %	

	December 31, 2012									
	Pension plans (1)					Welfare plans				
In millions	Level 1	Level 2	Level 3	Total	% of total	Level 1	Level 2	Level 3	Total	% of total
Cash	$14	$2	$-	$16	2 %	$1	$-	$-	$1	1 %
Equity securities:										
U.S. large cap (2)	69	181	-	250	30 %	-	38	-	38	55 %
U.S. small cap (2)	60	22	-	82	10 %	-	-	-	-	- %
International companies (3)	-	120	-	120	14 %	-	12	-	12	18 %

Emerging markets (4)	-	34	-	34	4 %	-	-	-	-	- %
Fixed income securities:										
Corporate bonds (5)	-	216	-	216	26 %	-	18	-	18	26 %
Other (or gov’t/muni bonds)	-	30	-	30	3 %	-	-	-	-	- %
Other types of investments:										
Global hedged equity (6)	-	-	38	38	4 %	-	-	-	-	- %
Absolute return (7)	-	-	36	36	4 %	-	-	-	-	- %
Private capital (8)	-	-	23	23	3 %	-	-	-	-	- %
Total assets at fair value	$143	$605	$97	$845	100 %	$1	$68	$-	$69	100 %
% of fair value hierarchy	17 %	72 %	11 %	100 %		1 %	99 %	- %	100 %	

(1) Includes $9 million at December 31, 2013 and $8 million at December 31, 2012 of medical benefit (health and welfare) component for 401h accounts to fund a portion of the other retirement benefits.

(2) Includes funds that invest primarily in U.S. common stocks.

(3) Includes funds that invest primarily in foreign equity and equity-related securities.

(4) Includes funds that invest primarily in common stocks of emerging markets.

(5) Includes funds that invest primarily in investment grade debt and fixed income securities.

(6) Includes funds that invest in limited / general partnerships, managed accounts, and other investment entities issued by non-traditional firms or “hedge funds.”

(7) Includes funds that invest primarily in investment vehicles and commodity pools as a “fund of funds.”

(8) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly / indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real-estate mezzanine loans.

The following is a reconciliation of our retirement plan assets in Level 3 of the fair value hierarchy.

In millions	Fair value measurements using significant unobservable inputs - Level 3 (1) Global hedged equity	Absolute return	Private capital	Total
Balance at December 31, 2011	$30	$34	$25	$89
Gains included in changes in net assets	3	2	3	8
Purchases	15	-	-	15
Sales	(10)	-	(5)	(15)
Balance at December 31, 2012	$38	$36	$23	$97
Gains included in changes in net assets	5	3	4	12
Purchases	-	-	-	-
Sales	-	-	(5)	(5)
Balance at December 31, 2013	$43	$39	$22	$104

(1) There were no transfers out of Level 3, or between Level 1 and Level 2 for any of the periods presented.

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 Consolidated Statements of Financial Position as of the dates presented.

	December 31, 2013		December 31, 2012	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities
Natural gas derivatives				
Quoted prices in active markets (Level 1)	$6	$(79)	$8	$(45)
Significant other observable inputs (Level 2)	67	(79)	96	(30)
Netting of cash collateral	43	78	33	36
Total carrying value (2) (3)	$116	$(80)	$137	$(39)
Interest rate derivatives				
Significant other observable inputs (Level 2)	$-	$-	$3	$-

(1) $3 million of premium at December 31, 2013 and $4 million at December 31, 2012 associated with weather derivatives have been excluded as they are accounted for based on intrinsic value.

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

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

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. The following table presents the carrying amount and fair value of our long-term debt as of the following dates.

	As of December 31,	
In millions	2013	2012
Long-term debt carrying amount	$3,813	$3,553

Long-term debt fair value (1)	3,956	4,057

(1) Fair value determined using Level 2 inputs.

Note 5 - Derivative Instruments

Derivative Instruments

Our risk management activities are monitored by our Risk Management Committee, which consists of members of senior management and is charged with reviewing and enforcing our risk management activities and policies. Our use of derivative instruments, including physical transactions, is limited to predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following types of derivative instruments and energy-related contracts to manage natural gas price, interest rate, weather, automobile fuel price and foreign currency risks:

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

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 December 31, 2013 and 2012 for agreements with such features, derivative instruments with liability fair values totaled $80 million and $39 million, respectively, for which we had posted no collateral to our counterparties. The maximum collateral that could be required with these features is $9 million. For more information, see "Energy Marketing Receivables and Payables" in Note 2. 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 $66 million, $72 million and $(17) million for the periods ended December 31, 2013, 2012 and 2011, respectively.

On April 4, 2013 we entered into two ten-year, $50 million fixed-rate forward-starting interest rate swaps to partially hedge any potential interest rate volatility prior to our issuance of the senior notes in the second quarter of 2013. The average interest rate on these swaps was 1.98%. Including existing $200 million of ten-year, 1.78% fixed-rate forward-starting interest rate swap hedges, which were executed on December 6, 2012, 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.

In May 2011, we entered into interest rate swaps related to the $300 million of outstanding 6.4% senior notes due in July 2016 that effectively converted $250 million from a fixed rate to a variable rate obligation. On September 6, 2012 we settled this $250 million fixed-rate to floating-rate interest rate swap.

The fair values of our interest rate swaps were reflected as a long-term derivative asset of $3 million at December 31, 2012. For more information on our debt, see Note 8.

The following table summarizes the various ways in which we account for our derivative instruments and the impact on our 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	Gains or losses on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings
	Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	
Not designated as hedges	Derivative carried at fair value	Realized and unrealized gains or losses on the derivative instrument are recognized in earnings
	Distribution operations' gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in cost of goods sold	Gains or losses on these derivative instruments are ultimately included in billings to customers and are recognized in cost of goods sold in the same period as the related revenues

Quantitative Disclosures Related to Derivative Instruments

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

In Bcf (1)	December 31, 2013 (2)	December 31, 2012
Hedge designation		
Cash flow hedges	6	6
Not designated as hedges	183	96
Total hedges	189	102
Hedge position		
Short position	(2,622)	(1,955)
Long position	2,811	2,057
Net long position	189	102

(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 two and six years.

Derivative Instruments in our Consolidated Statements of Financial Position

In accordance with regulatory requirements, gains and losses on derivative instruments used at Nicor Gas and Elizabethtown Gas in our distribution operations segment to hedge natural gas purchases for customer use are reflected in accrued natural gas costs within our Consolidated Statements of Financial Position until billed to customers. The following amounts represent the net realized gains (losses) related to these natural gas cost hedges for the years ended December 31.

In millions	2013	2012
Nicor Gas	$4	$(35)
Elizabethtown Gas	$(6)	$(28)

The following table presents the fair values and Consolidated Statements of Financial Position classifications of our derivative instruments:

In millions	Classification	December 31, 2013 Assets	December 31, 2013 Liabilities	December 31, 2012 Assets	December 31, 2012 Liabilities
Designated as cash flow hedges and fair value hedges					
Natural gas contracts	Current	$3	$(1)	$1	$(2)
Interest rate swap agreements	Current	-	-	3	-
Total		3	(1)	4	(2)
Not designated as cash flow hedges					
Natural gas contracts	Current	691	(761)	394	(355)
Natural gas contracts	Long-term	206	(220)	45	(50)
Total		897	(981)	439	(405)
Gross amount of recognized assets and liabilities (1)		900	(982)	443	(407)

Gross amounts offset in our Consolidated Statements of Financial Position (2)	(781)	902	(299)	368
Net amounts of assets and liabilities presented in our Consolidated Statements of Financial Position (3)	$119	$(80)	$144	$(39)

(1) The gross amounts of recognized assets and liabilities are netted within our 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 $121 million as of December 31, 2013 and $69 million as of December 31, 2012. Cash collateral is included in the "Gross amounts offset in our Consolidated Statements of Financial Position" line of this table.

(3) At December 31, 2013 and 2012 we held letters of credit from counterparties that would offset, under master netting arrangements, an insignificant portion of these assets.

Derivative Instruments on the Consolidated Statements of Income

The following table presents the impacts of our derivative instruments in our Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011.

In millions	2013	2012	2011
Designated as cash flow hedges			
Natural gas contracts - loss reclassified from OCI to cost of goods sold	$(1)	$(5)	$(6)
Interest rate swaps – gain (loss) reclassified from OCI to interest expense	(3)	(4)	2
Income tax benefit	1	3	1
Net of tax	(3)	(6)	(3)
Not designated as hedges			
Natural gas contracts - net fair value adjustments recorded in operating revenues (1)	(90)	34	40
Natural gas contracts - net fair value adjustments recorded in cost of goods sold (2)	2	(4)	(4)
Income tax benefit (expense)	34	(11)	(14)
Net of tax	(54)	19	22
Total (losses) gains on derivative instruments, net of tax	$(57)	$13	$19

(1) Associated with the fair value of existing derivative instruments at December 31, 2013, 2012 and 2011.

(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $5 million for the year ended December 31, 2013, $14 million for the year ended December 31, 2012 and $9 million for the year ended December 31, 2011.

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 years ended December 31, 2013, 2012 and 2011.

Our expected gains to be reclassified from OCI into cost of goods sold, operation and maintenance expense, interest expense and operating revenues and recognized in our Consolidated Statements of Income over the next 12 months is $2 million. These deferred gains are related to natural gas derivative contracts associated with retail operations' and with Nicor Gas' system use. The expected gains are based upon the fair values of these financial instruments at December 31, 2013.

Note 6 - Employee Benefit Plans

Oversight of Plans

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of our defined benefit retirement plans. Further, we have an Investment Policy (the Policy) for our pension and other retirement benefit plans whose goal is to preserve these plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the plans' assets are managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification.

We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund.

The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income securities (corporate and government obligations), cash and cash equivalents and other suitable investments.

Equity market performance and corporate bond rates have a significant effect on our reported funded status. Changes in the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) are mainly driven by the assumed discount rate. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is used by the AGL Plan, to determine the expected return on the plan assets component of net annual pension cost. The MRVPA is a calculated value. Gains and losses on plan assets are spread through the MRVPA based on the five-year smoothing weighted average methodology.

Pension Benefits

We sponsor the AGL Plan, which is a tax-qualified defined benefit retirement plan for our eligible employees. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant, including information related to the participant's earnings history, years of service and age. In 2012, we also sponsored two other tax-qualified defined benefit retirement plans for our eligible employees, a Nicor plan and a NUI plan. Effective as of December 31, 2012, the NUI plan and the Nicor plan were merged into the AGL Plan. The participants of the former Nicor and NUI plans are now being offered their benefits, as described below, through the AGL Plan.

We generally calculate the benefits under the AGL Plan based on age, years of service and pay. The benefit formula for the AGL Plan is currently a career average earnings formula. Participants who were employees as of July 1, 2000 and who were at least 50 years of age as of that date earned benefits until December 31, 2010 under a final average pay formula. Participants who were employed as of July 1, 2000, but did not satisfy the age requirement to continue under the final average earnings formula, transitioned to the career average earnings formula on July 1, 2000.

Effective January 1, 2012, the AGL Plan was frozen with respect to participation for non-union employees hired on or after that date. Such employees are entitled to employer provided benefits under their defined contribution plan that exceed defined contribution benefits for employees who participate in the defined benefit plan.

Participants in the former Nicor plan receive noncontributory defined pension benefits. These benefits cover substantially all employees of Nicor Gas and its affiliates that adopted the Nicor plan, hired prior to 1998. Pension benefits are based on years of service and the highest average annual salary for management employees and job level for collectively bargained employees (referred to as pension bands). The benefit obligation related to collectively bargained benefits considers the past practice of regular benefit increases.

Participants in the former NUI plan included substantially all of NUI Corporation's employees who were employed on or before December 31, 2005. Florida City Gas union employees, who until February 2008 participated in a union-sponsored multiemployer plan became eligible to participate in the AGL Plan in February 2008. The AGL Plan provides pension benefits to these participants based on years of credited service and final average compensation as of the plan freeze date. Effective December 31, 2005, participation and benefit accrual under the NUI Plan were frozen. As of January 1, 2006, former participants in that plan became eligible to participate in the AGL Plan.

Welfare Benefits

Until December 31, 2012, we sponsored two defined benefit retiree health care plans for our eligible employees, AGL Welfare Plan and the Nicor Welfare Benefit Plan (Nicor Welfare Plan). Eligibility for these benefits is based on age and years of service. Effective December 31, 2012, the Nicor Welfare Plan was terminated and as of January 1, 2013, all participants under that plan became eligible to participate in the AGL Welfare Plan. This change in plan participation eligibility did not affect the benefit terms. The Nicor Welfare Plan benefits described below are now being offered to such participants under the AGL Welfare Plan.

The AGL Welfare Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach the plan's retirement age while working for us. In addition, the AGL Welfare Plan provides life insurance for all employees if they have ten years of service at retirement. The state regulatory commissions have approved phase-in plans that defer a portion of the related benefits expense for future recovery. The AGL Welfare Plan terms include a limit on the employer share of costs at limits based on the coverage tier, plan elected and salary level of the employee at retirement.

Medicare eligible retirees covered by the AGL Welfare Plan, including all of those at least age 65, receive benefits through our contribution to a retiree health reimbursement arrangement account. Additionally, on the pre-65 medical coverage of the AGL Welfare Plan our expected cost is determined by a retiree premium schedule based on salary level and years of service. Due to the cap, there is no impact on the periodic benefit cost or on our accumulated projected benefit obligation for a change in the assumed healthcare cost trend rate for this portion of the plan.

The plan provisions that are applicable to prior participants in the Nicor Welfare Plan include health care and life insurance benefits to eligible retired employees and include a limit on the employer share of cost for employees hired after 1982.

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 provides for a prescription drug benefit under Medicare Part D as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Prescription drug coverage for the Nicor Gas Medicare-eligible population changed, effective January 1, 2013, from an employer-sponsored prescription drug plan with the Retiree Drug Subsidy to an Employer Group Waiver Plan (EGWP). The EGWP replaces the employer sponsored prescription drug plan. The expected savings is estimated to be approximately 12% of total Medicare eligible liability.

We also have a separate unfunded supplemental retirement health care plan that provides health care and life insurance benefits to employees of discontinued businesses. This plan is noncontributory with defined benefits. Net plan expenses were immaterial in 2013 and 2012. The APBO associated with this plan was $2 million at December 31, 2013, and $3 million at December 31, 2012.

Assumptions

We considered a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We based our discount rates separately for each plan on an above-mean yield curve provided by our actuaries that is derived from a portfolio of high quality (rated AA or better) corporate bonds with a yield higher than the regression mean curve and the equivalent annuity cash flows.

The components of our pension and welfare costs are set forth in the following table.

	Pension plans			Welfare plans		
Dollars in millions	2013	2012	2011	2013	2012	2011
Service cost	$29	$28	$14	$3	$4	$1
Interest cost	43	44	29	14	16	6
Expected return on plan assets	(62)	(64)	(33)	(6)	(5)	(5)
Net amortization of prior service credit	(2)	(2)	(2)	(5)	(3)	(4)
Recognized actuarial loss	35	34	14	8	9	2
Net periodic benefit cost	$43	$40	$22	$14	$21	$-
Assumptions used to determine benefit costs						
Discount rate (1)	4.2%	4.6%	5.4%	4.0%	4.5%	5.2%
Expected return on plan assets (1)	7.8%	8.4%	8.5%	7.8%	8.5%	8.2%
Rate of compensation increase (1)	3.7%	3.7%	3.7%	3.8%	3.8%	3.7%
Pension band increase (2)	2.0%	2.0%	2.0%	n/a	n/a	n/a

(1) Rates are presented on a weighted average basis.
(2) Only applicable to the Nicor Gas union employees.

The following tables present details about our pension and welfare plans.

	Pension plans		Welfare plans	
Dollars in millions	2013	2012	2013	2012
Change in plan assets				
Fair value of plan assets, January 1,	$ 837	$ 754	$77	$ 67
Actual return on plan assets	134	101	16	10
Employee contributions	-	-	3	1
Employer contributions	1	42	19	17
Benefits paid	(65)	(59)	(23)	(19)
Medicare Part D reimbursements	-	-	1	1
Plan curtailment and settlements	-	(1)	-	-
Fair value of plan assets, December 31,	$ 907	$ 837	$93	$ 77
Change in benefit obligation				
Benefit obligation, January 1,	$ 1,046	$ 968	$354	$ 397
Service cost	29	28	3	4
Interest cost	43	44	14	17
Actuarial loss (gain)	(93)	66	(26)	(22)

Plan amendments	-	-	-	(25)
Medicare Part D reimbursements	-	-	1	1
Benefits paid	(65)	(59)	(23)	(19)
Employee contributions	-	-	3	1
Plan curtailment and settlements	-	(1)	-	-
Benefit obligation, December 31,	$ 960	$ 1,046	$ 326	$ 354
Funded status at end of year	$ (53)	$ (209)	$ (233)	$ (277)
Amounts recognized in the Consolidated Statements of Financial Position consist of				
Long-term asset	$ 117	$ 33	$ -	$ -
Current liability	(2)	(2)	-	(12)
Long-term liability	(168)	(240)	(233)	(265)
Total liability at December 31,	$ (53)	$ (209)	$ (233)	$ (277)
Accumulated benefit obligation (1)	$ 902	$ 983	n/a	n/a
Assumptions used to determine benefit obligations				
Discount rate	5.0 %	4.2 %	4.7 %	4.0 %
Rate of compensation increase	3.7 %	3.7 %	3.7 %	3.7 %
Pension band increase (2)	2.0 %	2.0 %	n/a	n/a

(1) APBO differs from the projected benefit obligation in that the APBO excludes the effect of salary and wage increases.

(2) Only applicable to the Nicor Gas union employees.

A portion of the net benefit cost or credit related to these plans has been capitalized as a cost of constructing gas distribution facilities and the remainder is included in operation and maintenance expense.

57

Assumptions used to determine the health care benefit cost for the AGL Welfare Plan were as follows:

	2013	2012
Health care cost trend rate assumed for next year	8.4 %	8.4 %
Ultimate rate to which the cost trend rate is assumed to decline	4.5 %	4.5 %
Year that reaches ultimate trend rate	2030	2030

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in the assumed health care cost trend rates for the AGL Welfare Plan would have the following effects:

In millions	Effect on service and interest cost	Effect on benefit obligation
1% Health care cost trend rate increase	$-	$15
1% Health care cost trend rate decrease	-	(13)

As a result of a cap on expected cost for the AGL Welfare Plan, a one-percentage-point increase or decrease in the assumed health care trend does not materially affect periodic benefit cost or accumulated benefit obligation of the Plan.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in net regulatory assets and accumulated OCI as of December 31, 2013 and 2012:

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
December 31, 2013:						
Prior service credit	$-	$(20)	$(9)	$-	$(9)	$(20)
Net loss	61	60	210	30	271	90
Total	$61	$40	$201	$30	$262	$70
December 31, 2012:						
Prior service cost (credit)	$-	$(24)	$(11)	$(2)	$(11)	$(26)
Net loss	146	83	324	52	470	135
Total	$146	$59	$313	$50	$459	$109

The 2014 estimated amortization out of regulatory assets or accumulated OCI for these plans are set forth in the following table.

	Net Regulatory Asset		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
Amortization of prior service credit	$-	$(3)	$(2)	$-	$(2)	$(3)
Amortization of net loss	7	4	13	2	20	6

We recorded a regulatory asset for anticipated future cost recoveries of $108 million as of December 31, 2013 and $215 million as of December 31, 2012.

The following table presents the gross benefit payments expected for the years ended December 31, 2014 through 2023 for our pension and other retirement plans. There will be benefit payments under these plans beyond 2023.

In millions	Pension plans	Welfare plans
2014	$56	$20
2015	60	20
2016	63	21
2017	66	22
2018	68	23
2019-2023	366	123

Contributions

Our employees generally do not contribute to our pension and other retirement plans; however, Nicor Gas and pre-65 AGL retirees make nominal contributions to their health care plan. We fund the qualified pension plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. As required by The Pension Protection Act of 2006 (the Act), we calculate the minimum amount of funding using the traditional unit credit cost method.

The Act contained new funding requirements for single-employer defined benefit pension plans and established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. In 2013 we had no required contributions to the merged AGL Plan. In 2012 we contributed a combined $40 million to the AGL Plan and the NUI Plan. No contributions were made to the Nicor Plan in 2012.

Employee Savings Plan Benefits

We sponsor defined contribution retirement benefit plans that allow eligible participants to make contributions to their accounts up to specified limits. Under these plans, our matching contributions to participant accounts were $14 million in 2013, $12 million in 2012 and $7 million in 2011.

Note 7 – Stock-Based Compensation

General

The AGL Resources Inc. Omnibus Performance Incentive Plan, as amended and restated, and the Long-Term Incentive Plan (1999) provide for the grant of incentive and nonqualified stock options, stock appreciation rights, shares of restricted stock, restricted stock units, performance cash awards and other stock-based awards to officers and key employees. Under the Omnibus Performance Incentive Plan, as of December 31, 2013, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 641,371 shares. Under the Long-Term Incentive Plan (1999) as of December 31, 2013, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 640,082 shares. The maximum number of shares available for future issuance under the Omnibus Performance Incentive Plan is 4,288,563 shares, which includes 1,697,363 shares previously available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, pursuant to NYSE rules. No further grants will be made from the Long-Term Incentive Plan (1999) except for reload options that may be granted pursuant to the terms of certain outstanding options.

Accounting Treatment and Compensation Expense

We measure and recognize stock-based compensation expense for our stock-based awards over the requisite service period in our financial statements based on the estimated fair value at the date of grant for our stock-based awards using the modified prospective method. These stock awards include:

- stock options;
- stock and restricted stock awards; and
- performance units (restricted stock units, performance share units and performance cash units).

Performance-based stock awards and performance units contain market conditions. Stock options, restricted stock awards and performance units also contain a service condition.

We estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates. The authoritative guidance requires excess tax benefits to be reported as a financing cash inflow. The difference between the proceeds from the exercise of our stock-based awards and the par value of the stock is recorded within additional paid-in capital.

We have granted incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. Fair market value is defined under the terms of the applicable plans as the closing price per share of AGL Resources common stock for the trading day immediately preceding the grant date, as reported in The Wall Street Journal. Stock options generally have a three-year vesting period.

The following table provides additional information related to our cash and stock-based compensation awards.

In millions	2013	2012	2011

Compensation costs (1)	$22	$9	$14
Income tax benefits (1)	1	1	1
Excess tax benefits (2)	-	1	1

(1) Recorded in our Consolidated Statements of Income.
(2) Recorded in our Consolidated Statements of Financial Position.

Incentive and Nonqualified Stock Options

The stock options we granted generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant.

As of December 31, 2013 and 2012, we had no unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2013 was $21 million, and the income tax benefits from stock option exercises were immaterial. Cash received from stock option exercises for 2012 was $7 million, and the income tax benefit from stock option exercises was $1 million. The following tables summarize activity related to stock options for key employees and non-employee directors. As used in the table, intrinsic value for options means the difference between the current market value and the grant price.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding - December 31, 2010	2,229,112	$34.85		
Granted	1,685	42.19		
Exercised	(383,646)	31.11		
Forfeited	(23,997)	37.70		
Outstanding - December 31, 2011	1,823,154	$35.61		
Granted	-	-		
Exercised	(234,844)	32.07		
Forfeited	(59,720)	37.34		
Outstanding - December 31, 2012 (1)	1,528,590	$36.09	3.7	$6
Granted	-	-	-	
Exercised	(617,358)	35.37	2.3	
Forfeited	(12,500)	38.36	2.6	
Outstanding - December 31, 2013 (1) (2)	898,732	$36.55	3.0	$10

(1) All options outstanding at December 31, 2013 and 2012 were exercisable.
(2) The range of exercise prices for the options outstanding at December 31, 2013 was $30.70 to $43.85.

We measure compensation cost related to stock options based on the fair value of these awards at their date of grant using the Black-Scholes option-pricing model. There were no options granted in 2013 and 2012, and the number of options granted in 2011 was immaterial. We use shares purchased under our 2006 share repurchase program to satisfy exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Performance Units

In general, a performance unit is an award of the right to receive (i) an equal number of shares of our common stock, which we refer to as a restricted stock unit or (ii) cash, subject to the achievement of certain pre-established performance criteria, which we refer to as a performance cash unit. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. The compensation cost of restricted stock unit awards is equal to the grant date fair value of the awards, recognized over the requisite service period, determined according to the authoritative guidance related to stock compensation. The compensation cost of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, recognized over the requisite service period. No other assumptions are used to value these awards.

Restricted Stock Units In general, a restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria. In 2013, we granted 43,830 restricted stock units to certain employees, all of which were outstanding as of December 31, 2013. These restricted stock units had a performance measurement period that ended December 31, 2013. The performance measure, which related to earnings before interest, income tax, depreciation and amortization, was met. As such, the related restricted stock awards will occur in 2014.

Performance Share Unit Awards A performance share unit award represents the opportunity to receive cash and shares subject to the achievement of certain pre-established performance criteria. We granted performance share unit awards to certain officers. These awards have a performance measure that relates to the Company's relative total shareholder return relative to a group of peer companies. The recorded liability and maximum potential liability related to the 2013, 2012 and 2011 grants are as follows:

In millions	Measurement period end date	Fair value accrued at December 31, 2013	Maximum aggregate payout
Granted in 2011	December 31, 2013	$7	$12
Granted in 2012	December 31, 2014	$6	$18
Granted in 2013	December 31, 2015	$3	$18

Stock and Restricted Stock Awards

The compensation cost of both stock awards and restricted stock awards is equal to the grant date fair value of the awards, recognized over the requisite service period. No other assumptions are used to value the awards. We refer to restricted stock as an award of our common stock that is subject to time-based vesting or achievement of performance measures. Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment.

Stock Awards - Non-Employee Directors Non-employee director compensation may be paid in shares of our common stock in connection with initial election, the annual retainer, and chair retainers, as applicable. Stock awards for non-employee directors are 100% vested and non-forfeitable as of the date of grant. During 2013 we issued 26,915 shares with a weighted average fair value of $44.04 to our non-employee directors.

Restricted Stock Awards - Employees The following table summarizes the restricted stock awards activity for our employees during the last two years.

	Shares of restricted stock	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding - December 31, 2011 (1)	477,354		$34.40
Issued	268,840		40.08
Forfeited	(28,829)		39.07
Vested	(214,274)		36.45
Outstanding - December 31, 2012 (1)	503,091	1.8	$39.44
Issued	175,935	2.8	42.41
Forfeited	(33,352)	2.0	40.64
Vested	(204,421)	0.0	38.71
Outstanding - December 31, 2013 (1)	441,253	1.8	$40.82

(1) Subject to restriction.

Employee Stock Purchase Plan (ESPP)

We have a nonqualified, broad based ESPP for all eligible employees. As of December 31, 2013, there were 122,763 shares available for future issuance under this plan. Employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value, and we record an expense for the 15% purchase price discount. Employee ESPP contributions may not exceed $25,000 per employee during any calendar year.

	2013	2012	2011
Shares purchased on the open market	97,734	103,589	65,843
Average per-share purchase price	$42.96	$38.96	$40.55
Total purchase price discount	$628,358	$591,855	$401,346

Note 8 - Debt and Credit Facilities

Our financing activities, including long-term and short-term debt, are subject to customary approval or review by state and federal regulatory bodies. Our wholly-owned subsidiary, AGL Capital, was established to provide for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities and other financing arrangements. We fully and unconditionally guarantee all debt issued by AGL Capital. Nicor Gas is not permitted by regulation to make loans to affiliates or utilize AGL Capital for its financing needs. 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 Consolidated Statements of Financial Position.

		December 31, 2013				December 31, 2012			
Dollars in millions	Year(s) due	Weighted average interest rate (1)		Outstanding		Weighted average interest rate (1)		Outstanding	
Short-term debt									
Commercial paper - AGL Capital (2)	2014	0.4	%	$	857	0.5	%	$	1,063
Commercial paper- Nicor Gas (2)	2014	0.3			314	0.4			314
Total short-term debt		0.4	%	$	1,171	0.5	%	$	1,377
Current portion of long-term debt and capital leases									
Current portion of long-term debt	n/a	-		$	-	4.6		$	225
Current portion of capital leases	n/a	-			-	4.9			1
Total current portion of long-term debt and capital leases		-		$	-	4.6	%	$	226
Long-term debt - excluding current portion									
Senior notes	2015-2043	5.0	%	$	2,825	5.1	%	$	2,325
First mortgage bonds	2016-2038	5.6			500	5.6			500
Gas facility revenue bonds	2022-2033	1.0			200	1.2			200
Medium-term notes	2017-2027	7.8			181	7.8			181
Total principal long-term debt		4.9	%	$	3,706	5.0	%	$	3,206
Fair value adjustment of long-term debt (3)	2016-2038	n/a			91	n/a			103
Unamortized debt premium, net	n/a	n/a			16	n/a			18
Total non-principal long-term debt		n/a			107	n/a			121
Total long-term debt				$	3,813			$	3,327
Total debt				$	4,984			$	4,930

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the 12 months ended December 31, 2013 and 2012.
(2) As of December 31, 2013, the effective interest rates on our commercial paper borrowings were 0.4% for AGL Capital and 0.3% for Nicor Gas.
(3) See Note 4 for additional information on our fair value measurements.

Short-term Debt

Our short-term debt at December 31, 2013 and 2012 was composed of borrowings under our commercial paper programs.

Commercial Paper Programs We maintain commercial paper programs at AGL Capital and at Nicor Gas that consist of short-term, unsecured promissory notes that are used in conjunction with cash from operations to fund our seasonal working capital requirements. Working capital needs fluctuate during the year and are highest during the injection period in advance of the Heating Season. The Nicor Gas commercial paper program supports working capital needs at Nicor Gas, while all of our other subsidiaries and SouthStar participate in the AGL Capital commercial paper program. During 2013, our commercial paper maturities ranged from 1 to 123 days, and at December 31, 2013, remaining terms to maturity ranged from 2 to 99 days. During 2013, total borrowings and repayments netted to a payment of $206 million. For commercial paper issuances with original maturities over 3 months, borrowings and repayments were $374 million and $181 million, respectively.

Credit Facilities At December 31, 2013 and 2012, there were no outstanding borrowings under either the AGL Capital or Nicor Gas credit facilities. In November 2013, the lenders for our two credit facilities consented to our request to extend the maturity date of each facility by one year, in accordance with the terms of the respective credit agreements. The AGL Credit Facility and Nicor Gas Credit Facility maturity dates were extended to November 10, 2017 and December 15, 2017, respectively. The terms, conditions and pricing under the agreements remain unchanged.

Current Portion of Long-term Debt and Capital Leases The current portion of our long-term debt at December 31, 2012 was composed of the current portions of our long-term debt and capital lease obligations. Our capital leases consisted primarily of a sale/leaseback transaction of gas meters and other equipment that was completed in 2002 by Florida City Gas and expired in the second quarter 2013. In the second quarter 2012, Florida City Gas had the option to purchase the leased meters from the lessor at their fair market value, but it did not exercise this option.

Long-term Debt

Our long-term debt at December 31, 2013 and 2012 consisted of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1, 1989; senior notes; first mortgage bonds; and gas facility revenue bonds. Some of these issuances were completed in the private placement market. In determining that those specific bonds qualify for exemption from registration under Section 4(2) of the Securities Act of 1933, we relied on the facts that the bonds were offered only to a limited number of large institutional investors and each institutional investor that purchased the bonds represented that it was purchasing the bonds for its own account and not with a view to distribute them. We fully and unconditionally guarantee all of our senior notes. Additionally, substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds.

The majority of our long-term debt matures after fiscal year 2018. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	Amount (in millions)
2014	$-
2015	200
2016	545
2017	22
2018	155
Thereafter	2,784
Total	$3,706

Senior Notes 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 repay our senior notes that matured on April 15, 2013. There were no senior note issuances in 2012.

First Mortgage Bonds We acquired the first mortgage bonds of Nicor Gas, which were issued through the public and private placement markets, as a result of the 2011 merger.

Gas Facility Revenue Bonds We are party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) under which the NJEDA has issued a series of gas facility revenue bonds. These gas revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance are then loaned to us.

During 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. We 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.

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 pension adjustments, welfare benefits liability adjustments and accounting adjustments for cash flow hedges. Adjusting for these items, the following table contains our debt-to-capitalization ratios for the dates presented, which are below the maximum allowed.

	AGL Resources December 31,		Nicor Gas December 31,	
	2013	2012	2013	2012
Debt-to-capitalization ratio	57 %	58 %	55 %	55 %

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, as of December 31, 2013 and 2012.

Preferred Securities

At December 31, 2013 and 2012, we had 10 million shares of authorized, unissued Class A junior participating preferred stock, no par value, and 10 million shares of authorized, unissued preferred stock, no par value.

Note 9 - Equity

Treasury Shares

Our Board of Directors authorized us to purchase up to 8 million treasury shares through our repurchase plan, which expired on January 31, 2011. This plan was used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this plan were made in the open market or in private transactions at times, and in amounts that we deemed appropriate. We held the purchased shares as treasury shares and accounted for them using the cost method. We purchased no treasury shares in 2013 or 2012.

Dividends

Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors.

Additionally, we derive a substantial portion of our consolidated assets, earnings and cash flow from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. As with most other companies, the payment of dividends is restricted by laws in the states where we conduct business. In certain cases, our ability to pay dividends to our common shareholders is limited by (i) our ability to pay our debts as they become due in the usual course of business and satisfy our obligations under certain financing agreements, including our debt-to-capitalization covenant, (ii) our ability to maintain total assets below total liabilities, and (iii) our ability to satisfy our obligations to any preferred shareholders.

Accumulated Other Comprehensive Loss

Our share of comprehensive income (loss) includes net income plus OCI, which includes changes in fair value of certain derivatives designated as cash flow hedges, certain changes in pension and other retirement benefit plans and reclassifications for amounts included in net income less net income and OCI attributable to the noncontrolling interest. For more information on our derivative instruments, see Note 5. For more information on our pensions and retirement benefit obligations, see Note 6. Our other comprehensive income (loss) amounts are aggregated within our accumulated other comprehensive loss. The following table provides changes in the components of our accumulated other comprehensive loss balances, net of the related tax effects allocated to each component of OCI.

In millions (1)	Cash flow hedges	Retirement benefit plans	Total
As of December 31, 2010	$ (5)	$ (145)	$ (150)
Other comprehensive loss	(2)	(65)	(67)
As of December 31, 2011	(7)	(210)	(217)
Other comprehensive income (loss)	4	(5)	(1)
As of December 31, 2012	(3)	(215)	(218)
Other comprehensive income, before reclassifications	1	66	67
Amounts reclassified from accumulated other comprehensive loss	3	12	15
As of December 31, 2013	$ 1	$ (137)	$ (136)

(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 year ended December 31, 2013 and the ultimate favorable (unfavorable) impact on net income.

In millions (1)		
Cash flow hedges		
Natural gas contracts	$(1)	Cost of goods sold
Interest rate contracts	(3)	Interest expense, net
Total before income tax	(4)	
Income tax benefit	1	
Total cash flow hedges	(3)	
Retirement benefit plan amortization of		
Actuarial losses	(25)	See (2), below
Prior service credits	5	See (2), below
Total before income tax	(20)	
Income tax benefit	8	
Total retirement benefit plans	(12)	
Total reclassification for the period	$(15)	

(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.

Note 10 - Non-Wholly Owned Entities

Variable Interest Entities

On a quarterly basis we evaluate our variable interests in other entities, primarily ownership interests, to determine if they represent a variable interest entity (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 by us and Piedmont, is the only VIE for which we are the primary beneficiary, which requires us to consolidate its assets, liabilities and Statements of Income. Our conclusion that SouthStar is a VIE resulted from our equal voting rights with Piedmont not being proportional to our economic obligation to absorb 85% of losses or residual returns from the joint venture. We account for our ownership of SouthStar in accordance with authoritative accounting guidance which is described within Note 2.

SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to customers in Georgia, and under various other trade names to customers in Illinois, Ohio, Florida, Maryland, Michigan and New York. Following are additional factors we considered in determining that we have the power to direct SouthStar’s activities that most significantly impact its performance.

Operations

Our wholly owned subsidiaries, Nicor Gas and Atlanta Gas Light, provide the following services, which affect SouthStar’s operations:

- meter reading for SouthStar’s customers in Illinois and Georgia
- maintenance and expansion of the natural gas infrastructure in Illinois and Georgia
- assigning storage and transportation capacity used in delivering natural gas to SouthStar’s customers

Liquidity and capital resources

- guarantees of SouthStar's activities with, and its credit exposure to, its counterparties and to certain natural gas suppliers in support of SouthStar's payment obligations
- support of SouthStar's daily cash management activities and assistance ensuring SouthStar has adequate liquidity and working capital resources by allowing SouthStar to utilize the AGL Capital commercial paper program for its liquidity and working capital requirements in accordance with our services agreement.

Back office functions

- Accounting, information technology, credit and internal controls services in accordance with our services agreement

SouthStar's earnings are allocated entirely in accordance with the ownership interests and are seasonal in nature, with the majority 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. SouthStar's current liabilities consist primarily of accrued natural gas costs, other accrued expenses, customer deposits, derivative instruments and payables to us from its participation in AGL Capital's commercial paper program.

SouthStar's 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. As a result, our maximum exposure to a loss at SouthStar is considered to be immaterial. SouthStar's creditors have no recourse to our general credit beyond our corporate guarantees 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 and the aforementioned limited protections related to goodwill and intangible assets, 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 in our operating cash flows are also attributable to SouthStar's working capital changes 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.

Cash flows used in our investing activities include capital expenditures for SouthStar for the year ended December 31, of $3 million for 2013, $1 million for 2012 and $2 million for 2011. 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 or second quarter of each fiscal year. For the years ended December 31, 2013, 2012 and 2011, SouthStar distributed $17 million, $14 million and $16 million to Piedmont, respectively.

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 the noncontrolling interest on our Consolidated Statements of Financial Position and a financing activity on our Consolidated Statements of Cash Flows. These funds were used to reduce our commercial paper borrowings.

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

	December 31, 2013				December 31, 2012			
In millions	Consolidated (1)	SouthStar (2)	% (3)		Consolidated (1)	SouthStar (2)	% (3)	
Current assets	$2,895	$264	9	%	$2,836	$201	7	%
Goodwill and other intangible assets	1,972	133	7		1,847	-	-	
Long-term assets and other deferred debit	9,683	13	-		9,387	10	-	
Total assets	$14,550	$410	3	%	$14,070	$211	1	%
Current liabilities	$3,118	$95	3	%	$3,336	$62	2	%
Long-term liabilities and other deferred credits	7,819	-	-		7,343	-	-	
Total liabilities	10,937	95	1		10,679	62	1	
Equity	3,613	315	9		3,391	149	4	
Total liabilities and equity	$14,550	$410	3	%	$14,070	$211	1	%

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

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

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

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

	December 31,	
In millions	2013	2012
Operating revenues	$687	$576
Operating expenses		
Cost of goods sold	491	411
Operation and maintenance	72	63
Depreciation and amortization	7	2
Taxes other than income taxes	1	2
Total operating expenses	571	478
Operating income	$116	$98

Equity Method Investments

Triton We have an investment in Triton, a cargo container leasing company. Container equipment that is acquired by Triton is accounted for in tranches as defined in Triton's operating agreement, and investors make capital contributions to Triton to invest in each of the tranches. As of December 31, 2013 we had invested in seven tranches established by Triton. For the years ended December 31, 2013 and 2012, income from our equity method investment in Triton of $9 million and $11 million, respectively, was classified as other income on our Consolidated Statements of Income.

Horizon Pipeline We have a 50% owned joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC. Horizon Pipeline operates an approximate 70-mile natural gas pipeline from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas typically contracts for 70% to 80% of the total capacity.

Sawgrass Storage We own a 50% interest in Sawgrass Storage, a joint venture between us and a privately held energy exploration and production company. Sawgrass Storage was granted certification from the FERC in March 2012 for the development of an underground natural gas storage facility in Louisiana with 30 Bcf of working gas capacity. The FERC certificate is set to expire in March 2014.

In December 2013, the joint venture decided to terminate the development of this facility and recognized an impairment loss of $16 million, which reduced the carrying amount of the joint venture's long-lived assets to fair value. Consequently, we recognized our 50% interest in the loss during the fourth quarter of 2013, resulting in an $8 million ($5 million net of tax) charge to operating income.

The carrying amounts of our investments that are accounted for under the equity method at December 31 were as follows:

In millions	2013	2012
Triton	$70	$73
Horizon Pipeline	15	17
Other (1)	1	9
Total	$86	$99

(1) Includes our investment in Sawgrass Storage of $1 million at December 31, 2013 and $9 million at December 31, 2012.

Our net equity investment income for the years ended December 31, 2013, 2012 and 2011, was $3 million, $13 million and $1 million, respectively, which is reflected within other income on our Consolidated Statements of Income. The majority of our net equity investment income is attributable to our investment in Triton. For more information on our other income, see Note 2. During 2013 we received distributions of $17 million from our equity investees and $14 million in 2012.

Note 11 - Commitments, Guarantees and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual payments under our obligations and other commitments as of December 31, 2013.

In millions	Total	2014	2015	2016	2017	2018	2019 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$ 3,706	$ -	$ 200	$ 545	$ 22	$ 155	$ 2,784
Short-term debt	1,171	1,171	-	-	-	-	-
Environmental remediation liabilities (2)	447	70	82	80	48	63	104
Pipeline replacement program costs (2)	5	5	-	-	-	-	-
Total	$ 5,329	$ 1,246	$ 282	$ 625	$ 70	$ 218	$ 2,888
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$2,298	$733	$507	$299	$138	$102	$519
Interest charges (5)	2,899	185	175	161	147	145	2,086
Operating leases (6)	203	28	27	24	21	17	86
Asset management agreements (7)	19	8	5	4	2	-	-
Standby letters of credit, performance/surety bonds (8)	27	27	-	-	-	-	-
Other	5	1	2	2	-	-	-
Total	$5,451	$982	$716	$490	$308	$264	$2,691

(1) Excludes the $82 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $9 million interest rate swaps fair value adjustment.

(2) Includes charges recoverable through base rates or rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our Consolidated Statements of Financial Position.
(4) Includes charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers and demand charges associated with Sequent. The gas supply balance includes amounts for Nicor Gas and SouthStar gas commodity purchase commitments of 31 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2013, and is valued at $136 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.
(5) Floating rate interest charges are calculated based on the interest rate as of December 31, 2013 and the maturity date of the underlying debt instrument. As of December 31, 2013, we have $52 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2014.
(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with GAAP. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein. Our operating leases are primarily for real estate.
(7) Represent fixed-fee minimum payments for Sequent's affiliated asset management agreements.
(8) We provide guarantees to certain municipalities and other agencies and certain gas suppliers of SouthStar in support of payment obligations.

Substitute Natural Gas

In 2011, Illinois enacted laws that required Nicor Gas and other large utilities in Illinois to elect to either sign contracts to purchase SNG from coal gasification plants to be constructed in Illinois or file rate cases with the Illinois Commission in 2012, 2014 and 2016.

On October 11, 2011, the Illinois Power Agency (IPA) approved the form of a draft 30-year contract for the purchase by Nicor Gas of 20 Bcf per year of SNG from a proposed plant beginning as early as 2018. The purchase price of the SNG that may be produced from this proposed coal gasification plant may significantly exceed market prices for natural gas and is expected to be dependent upon a variety of factors, including the developer's financing, plant construction costs and volumes sold, which are currently not determinable. The Illinois law pertaining to this plant provides that the price paid for SNG purchased from the plant is to be considered prudent and not subject to review or disallowance by the Illinois Commission.

In November 2011, we filed a lawsuit against the IPA and the developer of this proposed plant contending that the draft contract approved by the IPA does not conform to certain requirements of the enabling legislation. The lawsuit is pending in circuit court in DuPage County, Illinois. In accordance with the enabling legislation, the draft contract approved by the IPA was submitted to the Illinois Commission for further approvals by that regulatory body. The final form of contract approved by the Illinois Commission modified the draft contract submitted by the IPA in various respects. We have appealed the Illinois Commission's decision to the circuit court in DuPage County, Illinois. As a result of pending litigation challenging aspects of the IPA and Illinois Commission decisions regarding the contract terms, we have not yet signed a contract with the developer to purchase SNG from the proposed plant.

Contingencies and Guarantees

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

Financial guarantees Tropic Equipment Leasing Inc. (TEL), a wholly owned subsidiary, holds our interest in Triton and has an obligation to restore to zero any deficit in its equity account for income tax purposes in the unlikely event that Triton is liquidated and a deficit balance remains. This obligation continues for the life of the Triton partnerships and any payment is effectively limited to the net assets of TEL, which were $16 million at December 31, 2013. We believe the likelihood of any such payment by TEL is remote. No liability has been recorded for this obligation.

Indemnities In certain instances, we have undertaken to indemnify current property owners and others against costs associated with the effects and/or remediation of contaminated sites for which we may be responsible under applicable federal or state environmental laws, generally with no limitation as to the amount. These indemnifications relate primarily to ongoing coal tar cleanup, as discussed in Environmental Matters. We believe that the likelihood of payment under our other environmental indemnifications is remote. No liability has been recorded for such indemnifications.

Regulatory Matters

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 should be recoverable from Marketers. The resolution of this imbalance will be decided by the Georgia Commission and we are unable to predict the ultimate outcome and recovery.

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 current and former operating sites. See Note 3 for additional information.

We are involved in an investigation by the EPA 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.

Litigation

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

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

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

On June 7, 2013 the Illinois Commission issued an order requiring us to refund $72 million to current Nicor Gas customers over a 12-month period. On July 1, 2013 we began refunding customers the full $72 million through our PGA mechanism. The amount refunded is based upon natural gas throughput and $29 million was refunded in 2013. The CUB is continuing to pursue its claim.

Other In addition to the matters set forth above, we are involved with legal or administrative proceedings before various courts and agencies with respect to general claims, taxes, environmental, gas cost prudence reviews and other matters. We are unable to determine the ultimate outcome of these other contingencies. We believe that these amounts are appropriately reflected in our financial statements, including the recording of appropriate liabilities when reasonably estimable.

Note 12 - Income Taxes

Income Tax Expense

The relative split between current and deferred taxes is due to a variety of factors including true ups of prior year tax returns, and most importantly, the timing of our property-related deductions. Components of income tax expense in the Consolidated Statements of Income are shown in the following table.

In millions	2013 (1)	2012 (1)	2011 (1)
Current income taxes			
Federal	$164	$8	$ (89)
State	35	4	1
Deferred income taxes			
Federal	(8)	128	192
State	(11)	20	18
Amortization of investment tax credits	(3)	(3)	(1)
Total	$177	$157	$121

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

The reconciliations between the statutory federal income tax rate of 35%, the effective rate and the related amount of income tax expense for the years ended December 31, in our Consolidated Statements of Income are presented in the following table.

In millions	2013 (1)	2012 (1)	2011 (1)
Computed tax expense at statutory rate	$165	$151	$105
State income tax, net of federal income tax benefit	20	19	14
Sale of Compass Energy	6	-	-
Tax effect of net income attributable to the noncontrolling interest	(7)	(6)	(6)
Amortization of investment tax credits	(3)	(3)	(1)
Affordable housing credits	(2)	(2)	(1)
Flexible dividend deduction	(2)	(2)	(2)
Change in control payments	-	-	9
Merger transaction costs	-	-	3
Total income tax expense on Consolidated Statements of Income	$177	$157	$121

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our Consolidated Statements of Financial Position. We measure the assets and liabilities using income tax rates that are currently in effect. We have provided a valuation allowance for some of these items that reduce our net deferred tax assets to amounts we believe are more likely than not to be realized in future periods. With respect to our continuing operations, we have net operating losses in various jurisdictions. Components that give rise to the net non-current accumulated deferred income tax liability are as follows.

In millions	As of December 31, 2013 (1)	2012 (1)
Accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$1,608	$1,528
Undistributed earnings of foreign subsidiaries	26	30
Investments in partnerships	18	26
Acquisition intangibles	11	24
Mark-to-market	-	22
Other	97	106
Total accumulated deferred income tax liabilities	1,760	1,736
Accumulated deferred income tax assets		
Unfunded pension and retiree welfare benefit obligation	92	145
Deferred investment tax credits	7	9
Mark-to-market	3	-
Other	44	43
Total accumulated deferred income tax assets	146	197
Valuation allowances (1) (2)	(14)	(22)
Total accumulated deferred income tax assets, net of valuation allowance	132	175
Net non-current accumulated deferred tax liability	$1,628	$1,561

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

(2) The total valuation allowance is $22 million, which is comprised of $3 million valuation allowance is due to the net operating losses of a former non-operating subsidiary that are not allowed in New Jersey and $19 million valuation allowance is related to our investment in Triton. In addition, $8 million of the total is classified as a valuation allowance against current deferred income tax assets. See Note 2 for more information regarding current deferred income taxes.

A deferred income tax liability is not recorded on undistributed foreign earnings that are expected to be indefinitely reinvested offshore. We consider, among other factors, actual cash investments offshore as well as projected cash requirements in making this determination. Changes in our investment or repatriation plans or circumstances could result in a different deferred income tax liability. We had $80 million of such cash and short-term investments on our Consolidated Statements of Financial Position as of December 31, 2013 and 2012. See Note 2 and Note 14 for more information about potential income taxes related to undistributed foreign earnings.

Tax Benefits

As of December 31, 2013 and December 31, 2012, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2014. As of December 31, 2013, we did not have a liability recorded for payment of interest or penalties associated with uncertain tax positions nor did we have any such interest or penalties during 2013 or 2012.

We file a U.S. federal consolidated income tax return and various state income tax returns. We are no longer subject to income tax examinations by the Internal Revenue Service or in any state for years before 2008.

Note 13 - 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 four operating segments - distribution operations, retail operations, wholesale services, midstream operations and one non-operating segment, other.

Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities in seven states. These utilities construct, manage, and maintain intrastate natural gas pipelines and distribution facilities. Although the operations of our distribution operations segment are geographically dispersed, the operating subsidiaries within the distribution operations segment are 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 in Illinois. Additionally, our retail operations segment provides home protection products and services. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, they provide natural gas asset management and/or related logistics services for each of our utilities, as well as for non-affiliated companies, natural gas storage arbitrage and related activities. Our midstream operations segment includes our non-utility storage and pipeline operations, including the development and operation of high-deliverability natural gas storage assets.

On April 4, 2014 we entered into a definitive agreement to sell Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position, and the financial results of these businesses are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in this note, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified into our other segment. See Note 14 for additional information. Our "other" segment includes aggregated subsidiaries that are not significant on a stand-alone basis and that do not fit into one of our other four operating segments.

The chief operating decision maker of the company is the Chairman, President and Chief Executive Officer who utilizes EBIT as the primary measure of profit and loss in assessing the results of our segments and operations. EBIT includes operating income and other income and expenses. Items we do not include in EBIT are income taxes and financing costs, including interest and debt expense, each of which we evaluate on a consolidated basis. Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the years ended December 31, 2013, 2012 and 2011 are shown in the following tables.

2013

In millions	Distribution operations (1)	Retail operations (1)	Wholesale services	Midstream operations	Other (4)	Intercompany eliminations	Consolidated (1)
Operating revenues from external parties	$3,230	$858	$60	$74	$8	$ (21)	$ 4,209
Intercompany revenues (2)	182	-	-	-	-	(182)	-
Total operating revenues	3,412	858	60	74	8	(203)	4,209
Operating expenses							
Cost of goods sold	1,687	564	21	33	-	(195)	2,110
Operation and maintenance	687	132	49	24	3	(8)	887
Depreciation and amortization	339	27	1	17	13	-	397
Taxes other than income taxes	167	3	3	5	9	-	187
Total operating expenses	2,880	726	74	79	25	(203)	3,581
Gain on disposition of assets	-	-	11	-	-	-	11
Operating income (loss)	532	132	(3)	(5)	(17)	-	639
Other income (expense)	14	-	-	(5)	7	-	16
EBIT	$546	$132	$(3)	$(10)	$(10)	$ -	$ 655
Identifiable and total assets (5)	$11,634	$685	$1,163	$713	$10,160	$ (10,088)	$ 14,267

Capital expenditures	$684	$9	$2	$12	$24	$ -	$ 731

2012

In millions	Distribution operations (1)	Retail operations (1)	Wholesale services	Midstream operations	Other (4)	Intercompany eliminations	Consolidated (1)
Operating revenues from external parties	$2,691	$733	$88	$78	$7	$ (35)	$ 3,562
Intercompany revenues (2)	167	2	-	-	-	(169)	-
Total operating revenues	2,858	735	88	78	7	(204)	3,562
Operating expenses							
Cost of goods sold	1,221	488	38	32	-	(196)	1,583
Operation and maintenance	642	114	48	19	1	(8)	816
Depreciation and amortization	347	18	2	14	13	-	394
Nicor merger expenses (3)	-	-	-	-	20	-	20
Taxes other than income taxes	140	4	4	5	6	-	159
Total operating expenses	2,350	624	92	70	40	(204)	2,972
Operating income (loss)	508	111	(4)	8	(33)	-	590
Other income	9	-	1	2	12	-	24
EBIT	$517	$111	$(3)	$10	$(21)	$ -	$ 614
Identifiable and total assets (5)	$11,256	$506	$1,218	$720	$9,848	$ (9,769)	$ 13,779
Capital expenditures	$649	$8	$3	$62	$53	$ -	$ 775

2011

In millions	Distribution operations (1)	Retail operations (1)	Wholesale services	Midstream operations	Other (4)	Intercompany eliminations	Consolidated (1)
Operating revenues from external parties	$ 1,438	$ 702	$ 98	$ 70	$ 4	$ (7)	$ 2,305
Intercompany revenues (2)	146	-	-	-	-	(146)	-
Total operating revenues	1,584	702	98	70	4	(153)	2,305
Operating expenses							
Cost of goods sold	625	534	41	33	-	(148)	1,085
Operation and maintenance	363	71	48	15	5	(5)	497
Depreciation and amortization	157	2	1	10	12	-	182
Nicor merger expenses (3)	-	-	-	-	57	-	57
Taxes other than income taxes	44	2	3	3	5	-	57
Total operating expenses	1,189	609	93	61	79	(153)	1,878
Operating income (loss)	395	93	5	9	(75)	-	427
Other income	6	-	-	-	1	-	7
EBIT	$ 401	$ 93	$ 5	$ 9	$ (74)	$ -	$ 434
Capital expenditures	$ 365	$ 2	$ 1	$ 35	$ 24	$ -	$ 427

(1) Amounts revised to include prior period adjustments. See Note 15 for additional information.

(2) Wholesale services records its energy marketing and risk management revenues on a net basis and its total operating revenues include intercompany revenues of $417 million in 2013, $350 million in 2012 and $449 million in 2011.

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

(4) Our other segment now also includes our investment in Triton, which was part of our cargo shipping segment that is classified as discontinued operations. For more information see Note 14.

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

Note 14 - Discontinued Operations

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

During the first quarter of 2014, based upon the negotiated sales price, we also recorded a goodwill impairment charge of $19 million, for which there is no income tax benefit. Additionally, we recognized a total of $7 million charge in the second and third quarters of 2014 related to the suspension of depreciation and amortization for assets that we were not compensated for by the buyer.

Our financial statements, including footnotes 1, 2, 4, 6, 7, 10, 11, 12 and 13 have been updated to recast our segment information and to give effect to the classification of Tropical Shipping as discontinued operations for all periods presented. The assets and liabilities of Tropical Shipping classified as held for sale on the Consolidated Statements of Financial Position are as follows:

	December 31,	
In millions	2013	2012
Current assets		
Cash and cash equivalents	$24	$23
Short-term investments	1	2
Receivables	36	34
Inventories	9	9
Other	1	8
Total current assets	71	76
Long-term assets and other deferred debits		
Property, plant and equipment, net	124	130
Goodwill	61	61
Intangible assets	19	20
Other	8	4
Total long-term assets and other deferred debits	212	215
Total assets held for sale	$283	$291
Current liabilities		
Accrued expenses	$7	$7
Other accounts payable - trade	11	8
Other	22	24
Total current liabilities	40	39
Total liabilities held for sale	$40	$39

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

	December 31,		
In millions	2013	2012	2011
Operating revenues	$365	$342	$19

Operating expenses			
Cost of goods sold	222	208	12
Operation and maintenance	110	106	6
Depreciation and amortization	19	22	1
Taxes other than income taxes	6	6	-
Total operating expenses	357	342	19
Operating income	8	-	-
Income before income taxes	8	-	-
Income tax expense (benefit)	3	(1)	-
Income from discontinued operations, net of tax	$5	$1	$-

Cash and cash equivalents As of December 31, 2013 and 2012, we had $31 million and $25 million of cash and short and long-term investments, respectively, in our Consolidated Statements of Financial Position held by Tropical Shipping that were included in the sale.

Property, plant and equipment A summary of Tropical Shipping's PP&E as of December 31, 2013 and 2012 is provided in the following table.

In millions	2013	2012
Shipping vessels and containers	$148	$145
Construction work in progress	4	1
Total PP&E, gross	152	146
Less accumulated depreciation	28	16
Total PP&E, net	$124	$130

Goodwill Changes in the amount of Tropical Shipping's goodwill for the twelve months ended December 31, 2013 and 2012 are provided below.

In millions	
Goodwill - December 31, 2011	$77
Adjustments to initial Nicor purchase price allocation and other	(16)
Goodwill - December 31, 2012	61
Goodwill - December 31, 2013	$61

Intangible Assets A summary of the intangible assets of Tropical Shipping, as of December 31, 2013 and 2012, is provided in the following table.

	Weighted average amortization period	December 31, 2013			December 31, 2012		
In millions	(in years)	Gross	Accumulated amortization	Net	Gross	Accumulated amortization	Net
Customer relationships	18	$6	$ -	$6	$6	$ -	$6
Trade names	15	15	(2)	13	15	(1)	14
Total		$21	$ (2)	$19	$21	$ (1)	$20

Amortization expense was $1 million in 2013, $1 million in 2012 and $0 in 2011.

Fair value of money market funds At December 31, 2013 and 2012, the fair value of our money market funds, which were held by Tropical Shipping, were as follows:

In millions	2013	2012
Money market funds (1)	$48	$66

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

Revenues We recognize revenues at the time vessels depart from port. Insurance premiums are recognized when the vessel carrying the insured cargo reaches its port of destination and the insured cargo is released to the consignee. The portion of premiums not earned at the end of the year is recorded as unearned premiums.

Repair and maintenance expense We record expense for repair and maintenance costs as incurred. This includes expenses for planned major maintenance, such as dry docking the vessels.

Employee Savings Plan Benefits Under our defined contribution retirement benefit plans, our matching contributions to participant accounts of Tropical Shipping were $2 million in each of 2013 and 2012. There were no such matching contributions in 2011.

Employee Stock Purchase Plan (ESPP) ESPP information related to the employees of Tropical Shipping follows.

	2013	2012	2011
Shares purchased on the open market	5,609	4,543	-
Average per-share purchase price	$42.96	$38.96	-
Total purchase price discount	$35,928	$26,423	-

75

Note 15 - Revision to Prior Period Financial Statements

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

The adjustments impacted each year since 1998.The cumulative decrease to January 1, 2011 retained earnings as a result of the adjustment was $26 million. The cumulative decrease through December 31, 2013 results in a decrease of $80 million to long term regulatory assets and $14 million to plant, property, and equipment. This adjustment resulted in a decrease to net income of $18 million, $7 million and $6 million for the years ended December 31, 2013, 2012 and 2011, respectively. These amounts will be recognized in future periods, when collected through rates from customers.

Additionally, we recorded other adjustments that we identified for prior periods that were included for completeness. The most significant of these include the intangible asset amortization. We have determined that our use of the straight-line method of amortizing our customer relationships and trade names was not applied consistent with the requirements of ASC 350 Intangibles-Goodwill and Other (ASC 350). ASC 350 requires an intangible asset be amortized over its useful life in a manner to reflect the pattern in which the economic benefits of the intangible assets are consumed or otherwise used up. We have determined that we should utilize the undiscounted cash flows utilized to determine their fair values, which can be reliably determined, for amortizing these assets. The impact for this adjustment was an increase to depreciation and amortization expense of $5 million in 2013 and 2012 and a decrease to intangible assets, net of $9 million as of December 31, 2013 and $5 million as of December 31, 2012. Other previously identified immaterial uncorrected amounts are reflected in the revised amounts.

We assessed the materiality of these adjustments on our financial statements and concluded they were not material to any prior annual or interim periods; however, in accordance with accounting standards since the cumulative adjustments were material to the current period, we revised our prior period financial statements as described below for these adjustments. The revision had no effect on reported cash flows and would not have changed incentive compensation for these periods. The following table presents the effects of the revisions to our Consolidated Statements of Financial Position as of December 31:

	2013			2012		
In millions	As filed (1)	Adjustment	Revised	As filed (1)	Adjustment	Revised
Current assets						
Regulatory assets	$162	$ (48)	$114	$145	$ (47)	$98
Other	57	(2)	55	21	-	21
Total current assets	2,945	(50)	2,895	2,883	(47)	2,836
Long-term assets and other deferred debits						
Property, plant and equipment, net	8,657	(14)	8,643	8,217	(12)	8,205

Regulatory assets	737	(32)	705	944	(5)	939
Intangible assets	154	(9)	145	76	(5)	71
Other	86	(1)	85	70	(2)	68
Total long-term assets and other deferred debits	11,711	(56)	11,655	11,258	(24)	11,234
Total assets	$14,656	$ (106)	$14,550	$14,141	$ (71)	$14,070
Current liabilities						
Accrued taxes	$85	$ -	$85	$53	$ (2)	$51
Other	148	(5)	143	112	-	112
Total current liabilities	3,123	(5)	3,118	3,338	(2)	3,336
Long-term liabilities and other deferred credits						
Accumulated deferred income taxes	1,667	(39)	1,628	1,588	(27)	1,561
Other	73	1	74	75	2	77
Total long-term liabilities and other deferred credits	7,857	(38)	7,819	7,368	(25)	7,343
Total liabilities and other deferred credits	$10,980	$ (43)	$10,937	$10,706	$ (27)	$10,679
Equity						
Additional paid in capital	$2,054	$ -	$2,054	$2,014	$ 1	$2,015
Retained earnings (2)	1,126	(63)	1,063	1,035	(45)	990
Total equity	3,676	(63)	3,613	3,435	(44)	3,391
Total liabilities and equity	$14,656	$ (106)	$14,550	$14,141	$ (71)	$14,070

(1) Reflects the reclassification of the assets and liabilities of Tropical Shipping as held for sale as filed in our Form 8-K on September 3, 2014.

(2) Reflects cumulative effects of adjustments for all periods. The impacts to each year are reflected in the tables on next page.

The following table presents the effects of the revisions to our Consolidated Statements of Income for the years ended December 31:

In millions, except per share amounts	2013 As filed (1)	2013 Adjustment	2013 Revised	2012 As filed (1)	2012 Adjustment	2012 Revised	2011 As filed (1)	2011 Adjustment	2011 Revised
Operating revenues	$ 4,252	$ (43)	$ 4,209	$ 3,580	$ (18)	$ 3,562	$ 2,319	$ (14)	$ 2,305
Operating expenses									
Cost of goods sold	2,110	-	2,110	1,583	-	1,583	1,085	-	1,085
Operation and maintenance	889	(2)	887	815	1	816	495	2	497
Depreciation and amortization	399	(2)	397	393	1	394	185	(3)	182
Nicor merger expenses	-	-	-	20	-	20	57	-	57
Taxes other than income taxes	187	-	187	159	-	159	57	-	57
Total operating expenses	3,585	(4)	3,581	2,970	2	2,972	1,879	(1)	1,878
Gain on disposition of assets	11	-	11	-	-	-	-	-	-
Operating income	678	(39)	639	610	(20)	590	440	(13)	427
Other income, net	17	(1)	16	24	-	24	7	-	7
Interest expense, net	(181)	11	(170)	(184)	1	(183)	(136)	2	(134)
Total other expense	(164)	10	(154)	(160)	1	(159)	(129)	2	(127)
Income before income taxes	514	(29)	485	450	(19)	431	311	(11)	300
Income tax expense	188	(11)	177	165	(8)	157	125	(4)	121
Income from continuing operations	326	(18)	308	285	(11)	274	186	(7)	179
Income from discontinued operations, net of tax	5	-	5	1	-	1	-	-	-
Net income	331	(18)	313	286	(11)	275	186	(7)	179
Less net income attributable to the noncontrolling interest	18	-	18	15	-	15	14	-	14

Net income attributable to AGL Resources Inc.	$ 313	$ (18)	$ 295	$ 271	$ (11)	$ 260	$ 172	$ (7)	$ 165
Per common share information									
Basic earnings per common share (2)									
Continuing operations	$ 2.61	$ (0.15)	$ 2.46	$ 2.31	$ (0.10)	$ 2.21	$ 2.14	$ (0.09)	$ 2.05
Discontinued operations	0.04	-	0.04	0.01	-	0.01	-	-	-
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.65	$ (0.15)	$ 2.50	$ 2.32	$ (0.10)	$ 2.22	$ 2.14	$ (0.09)	$ 2.05
Diluted earnings (loss) per common share (2)									
Continuing operations	$ 2.60	$ (0.15)	$ 2.45	$ 2.30	$ (0.10)	$ 2.20	$ 2.12	$ (0.08)	$ 2.04
Discontinued operations	0.04	-	0.04	0.01	-	0.01	-	-	-
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.64	$ (0.15)	$ 2.49	$ 2.31	$ (0.10)	$ 2.21	$ 2.12	$ (0.08)	$ 2.04

(1) Reflects the reclassification of the assets and liabilities of Tropical Shipping as held for sale as filed in our Form 8-K on September 3, 2014.

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

The following table presents the effects of the revisions to our Consolidated Statements of Cash Flows for the years ended December 31:

	2013			2012			2011		
In millions	As filed	Adjustment	Revised	As filed	Adjustment	Revised	As filed	Adjustment	Revised
Cash flows from operating activities									
Net income	$ 331	$ (18)	$ 313	$ 286	$ (11)	$ 275	$ 186	$ (7)	$ 179
Adjustments to reconcile net income to net cash flow provided by operating activities									
	399	(2)	397	393	1	394	185	(3)	182

Depreciation and amortization									
Deferred income taxes	(4)	(12)	(16)	164	(7)	157	214	(1)	213
Changes to certain assets and liabilities									
Accrued expenses	70	2	72	(23)	(1)	(24)	-	-	-
Other, net	40	30	70	(36)	18	(18)	(105)	11	(94)
Net cash flow provided by operating activities	$ 971	-	$ 971	$ 1,003	-	$ 1,003	$ 451	-	$ 451

77

Revision to Previously Reported Intangible Assets Disclosures As discussed above, the adjustment of our intangible asset amortization affects our customer relationships and trade names. The revisions to our previously reported intangible assets and accumulated amortization in our Original Filing are presented in the following table.

	December 31, 2013			December 31, 2012		
In millions	Gross	Accumulated amortization	Net	Gross	Accumulated amortization	Net
Customer relationships						
Retail operations as reported	$130	$ (15)	$115	$53	$ (6)	$47
Adjustments	-	(10)	(10)	-	(5)	(5)
Revised total	$130	$ (25)	$105	$53	$ (11)	$42
Trade names						
Retail operations as reported	$45	$ (6)	$39	$30	$ (2)	$28
Adjustments	-	1	1	-	-	-
Revised total	$45	$ (5)	$40	$30	$ (2)	$28

Amortization expense for all of our intangible assets for 2014 through 2018 is estimated to be as follows:

In millions	Reported amount	Adjustment	Adjusted amount
2014	$14	$6	$20
2015	14	4	18
2016	14	2	16
2017	14	1	15
2018	14	(1)	13

Note 16 - Selected Quarterly Financial Data (Unaudited)

The variance in our quarterly earnings is primarily the result of the seasonal nature of the distribution of natural gas to customers, the volatility within our wholesale services segment and the seasonality of our cargo shipping segment. During the Heating Season, natural gas usage and operating revenues are generally higher at our distribution operations and retail operations segments as more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. However, our base operating expenses, excluding cost of goods sold, interest expense and certain incentive compensation costs, are incurred relatively uniformly over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality. The effects of seasonality on our quarterly earnings have been impacted by our Nicor merger as we have more customers within our distribution operations segment that are impacted by weather.

Our 2013 operating revenues and operating income were higher than 2012. This was primarily as a result of colder-than-normal weather in 2013 compared to significantly warmer-than-normal weather in 2012. The increases in our operating revenues and operating income in 2012 compared to 2011 are primarily the result of the Nicor merger, which closed on December 9, 2011. See Note 2 and Note 13 for the impact the Nicor merger had on our segments, financial position and results of operations.

As discussed in Note 15, we identified an accounting issue related to our revenue recognition for certain of our regulatory infrastructure programs and revised our operating revenues, operation and maintenance expense, depreciation and amortization and income tax expense amounts. Additionally, we recorded other adjustments that we identified for prior periods that were included for completeness. The most significant of these include revising our intangible asset amortization. The following tables presents the effects of the revisions to our quarterly financial data for 2013, 2012 and 2011.

In millions, except per share amounts

2013	As filed (1)	March 31 Adjustments (2)	Revised
Operating revenues	$1,622	$(10)	$1,612
Operating income	298	(8)	290
EBIT	303	(8)	295
Net income from continuing operations	163	(4)	159
Net income from discontinued operations	1	-	1
Net income attributable to AGL Resources Inc.	154	(4)	150
Basic earnings per common share: (3)			
Continuing operations	1.30	(0.03)	1.27
Discontinued operations	0.01	-	0.01
Diluted earnings per common share: (3)			
Continuing operations	1.30	(0.04)	1.26
Discontinued operations	0.01	-	0.01

	June 30		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$816	$(11)	$805
Operating income	123	(10)	113
EBIT	130	(11)	119
Net income from continuing operations	51	(6)	45
Net loss from discontinued operations	(1)	-	(1)
Net income attributable to AGL Resources Inc.	49	(6)	43
Basic earnings (loss) per common share: (3)			
Continuing operations	0.42	(0.04)	0.38
Discontinued operations	(0.01)	-	(0.01)
Diluted earnings per common share: (3)			
Continuing operations	0.42	(0.04)	0.38
Discontinued operations	(0.01)	-	(0.01)

	September 30		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$586	$(12)	$574
Operating income	81	(11)	70
EBIT	88	(11)	77
Net income from continuing operations	27	(3)	24
Net income from discontinued operations	1	-	1
Net income attributable to AGL Resources Inc.	28	(3)	25
Basic earnings per common share: (3)			
Continuing operations	0.23	(0.03)	0.20
Discontinued operations	0.01	-	0.01
Diluted earnings per common share: (3)			
Continuing operations	0.23	(0.03)	0.20
Discontinued operations	0.01	-	0.01

	December 31		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$1,228	$(10)	$1,218
Operating income	176	(10)	166
EBIT	174	(10)	164
Net income from continuing operations	85	(5)	80
Net income from discontinued operations	4	-	4
Net income attributable to AGL Resources Inc.	82	(5)	77
Basic earnings per common share (3)			
Continuing operations	0.66	(0.05)	0.61
Discontinued operations	0.03	-	0.03
Diluted earnings per common share (3)			
Continuing operations	0.65	(0.04)	0.61
Discontinued operations	0.03	-	0.03

2012	March 31 As filed (1)	Adjustments (2)	Revised
Operating revenues	$ 1,320	$ (2)	$ 1,318
Operating income	263	(2)	261
EBIT	267	(2)	265
Net income from continuing operations	140	(1)	139
Net loss from discontinued operations	(1)	-	(1)
Net income attributable to AGL Resources Inc.	130	(1)	129
Basic earnings (loss) per common share:(3)			
Continuing operations	1.13	(0.02)	1.11
Discontinued operations	(0.01)	-	(0.01)
Diluted earnings per common share:(3)			
Continuing operations	1.12	(0.01)	1.11
Discontinued operations	(0.01)	-	(0.01)

	June 30		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$606	$(2)	$604
Operating income	95	(5)	90
EBIT	104	(5)	99
Net income from continuing operations	37	(3)	34
Net loss from discontinued operations	(2)	-	(2)
Net income attributable to AGL Resources Inc.	34	(3)	31
Basic earnings (loss) per common share: (3)			
Continuing operations	0.30	(0.02)	0.28
Discontinued operations	(0.02)	-	(0.02)
Diluted earnings per common share: (3)			
Continuing operations	0.30	(0.02)	0.28
Discontinued operations	(0.02)	-	(0.02)

	September 30		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$531	$(5)	$526
Operating income	56	(4)	52
EBIT	61	(4)	57
Net income from continuing operations	9	(3)	6
Net income from discontinued operations	-	-	-
Net income attributable to AGL Resources Inc.	9	(3)	6
Basic earnings per common share: (3)			
Continuing operations	0.08	(0.03)	0.05
Discontinued operations	-	-	-
Diluted earnings per common share: (3)			
Continuing operations	0.08	(0.03)	0.05
Discontinued operations	-	-	-

	December 31		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$1,123	$(9)	$1,114
Operating income	196	(9)	187
EBIT	202	(9)	193
Net income from continuing operations	99	(4)	95
Net income from discontinued operations	4	-	4
Net income attributable to AGL Resources Inc.	98	(4)	94
Basic earnings per common share (3)			
Continuing operations	0.80	(0.03)	0.77
Discontinued operations	0.03	-	0.03
Diluted earnings per common share (3)			
Continuing operations	0.80	(0.04)	0.76
Discontinued operations	0.04	-	0.04

		March 31	
2011	As filed (1)	Adjustments (2)	Revised
Operating revenues	$878	$(2)	$876
Operating income	238	(2)	236
EBIT	239	(2)	237
Net income from continuing operations	134	(1)	133
Net income attributable to AGL Resources Inc.	124	(1)	123
Basic earnings per common share:(3)			
Continuing operations	1.60	(0.02)	1.58
Diluted earnings per common share:(3)			
Continuing operations	1.59	(0.01)	1.58

	June 30		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$375	$(4)	$371
Operating income	60	(2)	58
EBIT	62	(2)	60
Net income from continuing operations	19	(2)	17
Net income attributable to AGL Resources Inc.	18	(2)	16
Basic earnings per common share:(3)			
Continuing operations	0.23	(0.02)	0.21
Diluted earnings per common share:(3)			
Continuing operations	0.23	(0.02)	0.21

	September 30		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$295	$(4)	$291
Operating income	24	(5)	19
EBIT	25	(5)	20
Net loss from continuing operations	(4)	(2)	(6)
Net loss attributable to AGL Resources Inc.	(3)	(2)	(5)
Basic loss per common share:(3)			
Continuing operations	(0.04)	(0.03)	(0.07)
Diluted loss per common share: (3)			
Continuing operations	(0.04)	(0.03)	(0.07)

	December 31		
	As filed (1)	Adjustments (2)	Revised
Operating revenues	$771	$(4)	$767
Operating income	118	(4)	114
EBIT	121	(4)	117
Net income from continuing operations	37	(2)	35
Net income attributable to AGL Resources Inc.	33	(2)	31
Basic earnings per common share (3)			
Continuing operations	0.37	(0.02)	0.35
Diluted earnings per common share (3)			
Continuing operations	0.37	(0.02)	0.35

(1) Amounts recast to reflect discontinued operations. See Note 14 for additional information.
(2) Amounts revised for prior period adjustments. See Note 15 for additional information.
(3) Excludes net income attributable to the noncontrolling interest.

Our basic and diluted earnings per common share are calculated based on the weighted daily average number of common shares and common share equivalents outstanding during the quarter. Those totals differ from the basic and diluted earnings per common share attributable to AGL Resources Inc. common shareholders shown in the Consolidated Statements of Income, which are based on the weighted average number of common shares and common share equivalents outstanding during the entire year.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

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”), are designed to provide reasonable 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. No system of controls, no matter how well designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases.

Under the supervision of and with the participation of our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2013. Based on this evaluation, at the time our Annual Report on Form 10-K for the year ended December 31, 2013 was filed on February 6, 2014, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2013. Subsequent to that evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were not effective as of December 31, 2013 because of the material weakness in our internal control over financial reporting described in our Management’s Report on Internal Control Over Financial Reporting (as restated) included in Item 8 herein.

Management's Annual Report on Internal Control over Financial Reporting (as restated)

For "Management's Annual Report on Internal Control over Financial Reporting" see Item 8 of this Report (which information is incorporated herein by reference).

Remediation Plan

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

- Reviewed all existing regulatory programs to ensure the proper evaluation of deferral components and proper treatment of allowed versus incurred costs pursuant to the accounting guidance. This review was completed prior to the issuance of revised consolidated financial statements.

- Complete training for all appropriate personnel regarding the applicable accounting guidance and requirements through meetings concurrent with the process to evaluate all infrastructure and other regulated programs.

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

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

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

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2013, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

(1) Financial Statements Included in Item 8 are the following:

- Report of Independent Registered Public Accounting Firm
- Management's Report on Internal Control Over Financial Reporting
- Consolidated Statements of Financial Position as of December 31, 2013 and 2012
- Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Equity for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011
- Notes to Consolidated Financial Statements

(2) Financial Statement Schedules

Financial Statement Schedule II. Valuation and Qualifying Accounts - Allowance for Uncollectible Accounts and Income Tax Valuations for Each of the Three Years in the Period Ended December 31, 2013. Schedules other than those referred to above are omitted and are not applicable or not required, or the required information is shown in the financial statements or notes thereto.

Exhibits

Exhibit Number	Description of Exhibit	Filer	The Filings Referenced for Incorporation by Reference
2.1	Agreement and Plan of Merger, as amended, dated December 6, 2010	AGL Resources	December 7, 2010, Form 8-K, Exhibit 2.1
2.2	Waiver entered into as of February 4, 2011	AGL Resources	February 9, 2011, Form 8-K, Exhibit 2.1
3.1	Amended and Restated Articles of Incorporation filed December 9, 2011	AGL Resources	December 13, 2011, Form 8-K, Exhibit 3.1
3.2	Bylaws, as amended on July 31, 2012	AGL Resources	August 6, 2012, Form 8-K, Exhibit 3.1
4.1	Specimen form of Common Stock certificate	AGL Resources	September 30, 2007, Form 10-Q, Exhibit 4.1
4.2.a	Form of AGL Capital Corporation 6.00% Senior Notes due 2034	AGL Resources	September 27, 2004, Form 8-K, Exhibit 4.1
4.2.b	Form of Guarantee of AGL Resources Inc. dated September 27, 2004	AGL Resources	September 27, 2004, Form 8-K, Exhibit 4.3
4.3.a	AGL Capital Corporation 4.95% Senior Notes due 2015	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.1
4.3.b	Guarantee of AGL Resources Inc. dated December 20, 2004	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.3
4.4.a	AGL Capital Corporation 6.375% Senior Notes due 2016	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.1
4.4.b	Guarantee of AGL Resources Inc. dated December 14, 2007	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.2
4.5.a	AGL Capital Corporation 5.25% Senior Notes due 2019	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.1
4.5.b	Guarantee of AGL Resources Inc. dated August 10, 2009	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.2
4.6.a	AGL Capital Corporation 5.875% Senior Notes due 2041	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.1
4.6.b	Guarantee of AGL Resources Inc. dated March 21, 2011	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.2
4.7.a	Form of AGL Capital Corporation 3.50% Senior Notes due 2021	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.1
4.7.b	Form of Guarantee of AGL Resources Inc. dated September 2011	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.2
4.8.a	Form of AGL Capital Corporation Series A Senior Notes due 2016	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.1
4.8.b			

	Form of AGL Capital Corporation Series B Senior Notes due 2018	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.2
4.9.a	AGL Capital Corporation 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.9.b	AGL Resources Inc. Guarantee related to the 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.10.a	Indenture dated December 1, 1989	Atlanta Gas Light	File No. 33-32274, Form S-3, Exhibit 4(a)
4.10.b	First Supplemental Indenture dated March 16, 1992	Atlanta Gas Light	File No. 33-46419, Form S-3, Exhibit 4(a)
4.11	Indenture dated February 20, 2001	AGL Resources	September 17, 2001, File No. 333-69500, Form S-3, Exhibit 4.2
4.12.a	Indenture dated January 1, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.01
4.12.b	Indenture dated February 9, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.02
4.12.c	Supplemental Indenture dated February 15, 1998	Nicor Gas	December 31, 1997, Form 10-K, Exhibit 4.19
4.12.d	Supplemental Indenture dated May 15, 2001	Nicor Gas	July 20, 2001, File No. 333-65486, Form S-3, Exhibit 4.18
4.12.e	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.09
4.12.f	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.10
4.12.g	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.11
4.12.h	Supplemental Indenture dated December 1, 2006	Nicor Gas	December 31, 2006, Form 10-K, Exhibit 4.11
4.12.i	Supplemental Indenture dated August 1, 2008	Nicor Gas	September 30, 2008, Form 10-Q, Exhibit 4.01
4.12.j	Supplemental Indenture dated July 23, 2009	Nicor Gas	June 30, 2009, Form 10-Q, Exhibit 4.01
4.12.k	Supplemental Indenture dated February 1, 2011	Nicor Gas	December 31, 2010, Form 10-K, Exhibit 4.12
4.12.l	Supplemental Indenture dated October 26, 2012	Nicor Gas	September 30, 2012, Form 10-Q, Exhibit 4
10.1.a +	2006 Non-Employee Directors Equity Compensation Plan, amended and restated as of December 9, 2011	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.2
10.1.b +	1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 1997, Form 10-Q, Exhibit 10.1.b
10.1.c +	First Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	March 31, 2000, Form 10-Q, Exhibit 10.5
10.1.d +	Second Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.4
10.1.e +	Third Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.5
10.1.f +			

	Fourth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.m
10.1.g +	Fifth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.l
10.1.h +	Form of Stock Award Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.aj
10.1.i +	Form of Nonqualified Stock Option Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.ak
10.1.j +	Form of Director Indemnification Agreement dated April 28, 2004	AGL Resources	June 30, 2004, Form 10-Q, Exhibit 10.3
10.1.k +	Long-Term Incentive Plan, as amended and restated as of January 1, 2002	AGL Resources	March 31, 2002, Form 10-Q, Exhibit 99.2
10.1.l +	First amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.b
10.1.m +	Second amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.l
10.1.n +	Third amendment to the Long-Term Incentive Plan, as amended and restated	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ad
10.1.o +	Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	March 14, 2011, Schedule 14A, Annex A
10.1.p +	Form of Restricted Stock Unit Agreement under Omnibus Performance Incentive Plan, as amended and Restated	AGL Resources	December 31, 2011, Form 10-K, Exhibit 10.1.ae
10.1.q +	Form of Restricted Stock Agreement under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2011, Form 10-K, Exhibit 10.1.af
10.1.r +	Form of Performance Share Unit Award under Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1r
10.1.s +	2007 Omnibus Performance Incentive Plan	AGL Resources	March 19, 2007, Schedule 14A, Annex A
10.1.t +	First Amendment to the 2007 Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ai
10.1.u +	Form of Incentive Stock Option Agreement – 2007 Omnibus Performance Incentive Plan	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.b
10.1.v +	Form of Nonqualified Stock Option Agreement – 2007 Omnibus Performance Incentive Plan	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.c
10.1.w +	Form of Incentive Stock Option Agreement and Nonqualified Stock Option Agreement for key employees (LTIP)	AGL Resources	September 30, 2004, Form 10-Q, Exhibit 10.1
10.1.x +	Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.1
10.1.y +	Form of Nonqualified Stock Option Agreement with the reload provision	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.2

	(Officer Incentive Plan)		
10.1.z +	Nonqualified Savings Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.av
10.1.aa +	First Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1aa
10.1.ab +	Second Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1ab
10.1.ac +	Third Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ac
10.1.ad +	Description of Supplemental Executive Retirement Plan for John W. Somerhalder II	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ay
10.1.ae +	Excess Benefit Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.az
10.1.af +	Form of Continuity Agreement dated December 19, 2013	AGL Resources	December 19, 2013, Form 8-K, Exhibit 10.1
10.1.ag +	Description of compensation for each of John W. Somerhalder II, Andrew W. Evans, Henry P. Linginfelter, Paul R. Shlanta and Peter I. Tumminello (our Named Executive Officers for the year ended December 31, 2013)	AGL Resources	Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held April 30, 2013 filed March 15, 2013.
10.2.a	Form of Commercial Paper Dealer Agreement	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.79
10.2.b	Guarantee dated October 5, 2000 of payments on promissory notes	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.80
10.4	Note Purchase Agreement dated August 31, 2011	AGL Resources	September 7, 2011, Form 8-K, Exhibit 10.1
10.5	Final Allocation Agreement dated January 3, 2008	Nicor	December 31, 2007, Form 10-K, Exhibit 10.64
10.6	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	AGL Resources	September 30, 2013, Form 10-Q, Exhibit 10
10.7	Credit Agreement dated as of December 15, 2011(1)	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.1
10.8.a	Amended and Restated Credit Agreement dated as of November 10, 2011(2)	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.1
10.8.b	Guarantee Agreement dated as of November 10, 2011	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.2
10.9	Bank Rate Mode Covenants Agreement, dated as of February 26, 2013	AGL Resources	March 1, 2013, Form 8-K, Exhibit 10.1
10.10	Loan Agreement dated as of February 1, 2013	AGL Resources	March 1, 2013, Form 8-K, Exhibit 10.2
10.11	Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.1
10.12	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.2
10.13			

	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.3
10.14	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	March 27, 2013, Form 8-K, Exhibit 10.4
12	Statement of Computation of Ratio of Earnings to Fixed Charges	AGL Resources	Filed herewith
14	Code of Ethics for the Chief Executive Officer and Senior Financial Officers	AGL Resources	December 31, 2004, Form 10-K, Exhibit 14
21	Subsidiaries of AGL Resources Inc.	AGL Resources	December 31, 2013, Form 10-K, Exhibit 21
23	Consent of PricewaterhouseCoopers LLP	AGL Resources	Filed herewith
24	Powers of Attorney	AGL Resources	December 31, 2013, Form 10-K, Exhibit 24
31.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
31.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
32.1	Certification of John W. Somerhalder II	AGL Resources	Filed herewith
32.2	Certification of Andrew W. Evans	AGL Resources	Filed herewith
101.INS	XBRL Instance Document	AGL Resources	Filed herewith
101.SCH	XBRL Taxonomy Extension Schema	AGL Resources	Filed herewith
101.CAL	XBRL Taxonomy Extension Calculation Linkbase	AGL Resources	Filed herewith
101.DEF	XBRL Taxonomy Definition Linkbase	AGL Resources	Filed herewith
101.LAB	XBRL Taxonomy Extension Labels Linkbase	AGL Resources	Filed herewith
101.PRE	XBRL Taxonomy Extension Presentation Linkbase	AGL Resources	Filed herewith

\+ Management contract, compensatory plan or arrangement.

(1) In November 2013, the Credit Agreement commitment terms were extended to a maturity date of December 15, 2017 via an approved extension request.

(2) In November 2013, the Amended and Restated Credit Agreement commitment terms were extended to a maturity date of November 10, 2017 via an approved extension request.

(b) Exhibits filed as part of this report.

See Item 15(a)(3).

(c) Financial statement schedules filed as part of this report.

See Item 15(a)(2).

SIGNATURES

In accordance with Section 13 or 15(d) 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, on November 7, 2014.

AGL RESOURCES INC.

By: /s/ John W. Somerhalder II
John W. Somerhalder II
Chairman, President and Chief Executive Officer

Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2013.

In millions	Balance at beginning of period	Additions Charged to costs and expenses	Charged to other accounts	Deductions	Balance at end of period
2011					
Allowance for uncollectible accounts	$ 16	$ 20	$ -	$ (19)	$ 17
Income tax valuation	3	-	-	-	3
2012					
Allowance for uncollectible accounts	$ 17	$ 25	$ 3	$ (17)	$ 28
Income tax valuation	3	-	19	-	22
2013					
Allowance for uncollectible accounts	$ 28	$ 37	$ -	$ (36)	$ 29
Income tax valuation	22	-	-	-	22

86