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

FORM 10-K

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.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2014 Annual Meeting of Shareholders (Proxy Statement) to be held on April 29, 2014, are incorporated by reference in Part III of this Form 10-K.

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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
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

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PART I

ITEM 1. BUSINESS

Unless the context requires otherwise, references to “we,” “us,” “our” and the “company” are intended to mean AGL Resources Inc. The operations and businesses described in this filing are owned and operated, and management services are provided, by distinct direct and indirect subsidiaries of AGL Resources. AGL Resources was organized and incorporated in 1995 under the laws of the State of Georgia.

Business Overview

AGL Resources, headquartered in Atlanta, Georgia, is an energy services holding company whose primary business is the distribution of natural gas through our natural gas distribution utilities. We also are involved in several other businesses that are mainly related and complementary to our primary business. Our operating segments consist of the following five operating and reporting segments which are consistent with how management views and manages our businesses.

Distribution Operations
- Serves 4.5 million customers across 7 states
- Performance driven by customer growth and/or usage, regulatory outcomes and infrastructure investment

Retail Operations
- Serves 620,000 energy customers and 1.1 million service contracts across 17 states
- Performance driven by market leading position in Georgia as well as our June 2013 acquisition of approximately 33,000 residential and commercial relationships and our January 2013 acquisition of approximately 500,000 service contracts

Wholesale Services
- Engages in natural gas storage, gas pipeline arbitrage and provides natural gas asset management and/or related logistics services for most of our utilities, as well as for non-affiliated companies
- Sequent’s portfolio of storage and transportation capacity is well positioned to serve customers and capture value under improving market conditions but remains subject to volatility in reported earnings due to changes in natural gas prices

Midstream Operations
- Consists primarily of high deliverability natural gas storage facilities
- Business remains challenged due to weak seasonal spreads and continued oversupply of natural gas

Cargo Shipping
- Provides shipping services to, from and between the Bahamas and the Caribbean
- Includes Seven Seas and our investment in Triton
- Business improving due to higher volumes

For more information on our segments, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Results of Operations” and Note 13 to our consolidated financial statements under Item 8 herein.

Merger with Nicor

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. As a result, we are currently one of the nation’s largest natural gas distribution companies based on customer count. The effects of Nicor’s results of operations and financial condition are reflected for the 12 months ended December 31, 2013 and 2012, while our 2011 results include activity from December 10, 2011 through December 31, 2011.

Distribution Operations

Our distribution operations segment is the largest component of our business and includes seven natural gas local distribution utilities with their primary focus being the safe and reliable delivery of natural gas. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

Utility	State	Approximate

		Number of customers (in thousands)	miles of pipe
Nicor Gas	Illinois	2,195	34,000
Atlanta Gas Light	Georgia	1,547	32,600
Virginia Natural Gas	Virginia	284	5,500
Elizabethtown Gas	New Jersey	279	3,200
Florida City Gas	Florida	105	3,500
Chattanooga Gas	Tennessee	63	1,600
Elkton Gas	Maryland	6	100
Total		4,479	80,500

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Competition and Customer Demand

All of our utilities face competition from other energy products. Our principal competitors are electric utilities and oil and propane providers serving the residential, commercial and industrial markets throughout our service areas. Additionally, the potential displacement or replacement of natural gas appliances with electric appliances is a competitive factor.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer or builder makes decisions as to which types of equipment to install. Customers generally continue to use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- changes in the availability or price of natural gas and other forms of energy;
- general economic conditions;
- energy conservation;
- legislation and regulations;
- the cost and capability to convert from natural gas to alternative fuels;
- weather;
- new commercial construction; and
- new housing starts.

We continue to develop and grow our business through the use of a variety of targeted marketing programs designed to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes and commercial 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.

The natural gas related 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. In addition, we partner with numerous third-party entities such as builders, realtors, plumbers, mechanical contractors, architects and engineers to market the benefits of natural gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Sources of Natural Gas Supply and Transportation Services

Procurement plans for natural gas supply and transportation to serve our regulated utility customers are reviewed and approved by our state utility commissions. We purchase natural gas supplies in the open market by contracting with producers, marketers and from our wholly owned subsidiary, Sequent, under asset management agreements. We also contract for transportation and storage services from interstate pipelines that are regulated by the FERC. On occasion, when firm pipeline services are temporarily not needed, we may release the services in the secondary market under FERC-approved capacity release provisions or utilize asset management arrangements, thereby reducing the net cost of natural gas charged to customers for most of our utilities. Peak-use requirements are met through utilization of company-owned storage facilities, pipeline transportation capacity, purchased storage services, peaking facilities and other supply sources, arranged by either our transportation customers or us. We have been able to obtain sufficient supplies of natural gas to meet customer requirements. We believe natural gas supply and pipeline capacity will be sufficiently available to meet market demands in the foreseeable future.

Transportation Our utilities use firm pipeline entitlements, storage services and/or peaking capacity contracted with interstate capacity providers to serve the firm natural gas supply needs of our customers. In addition, Nicor Gas, Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas operate on-system LNG facilities, underground natural gas storage fields and/or propane/air plants to meet the gas supply and deliverability requirements of their customers in the winter period. Generally, we work to build a portfolio of year-round firm transportation, seasonal storage and short-duration peaking services that will meet the needs of our customers under severe weather conditions with adequate operational flexibility to reliably manage the variability inherent in servicing customers using natural gas for space heating. Including seasonal storage and peaking services in this portfolio is more efficient and cost effective than reserving firm pipeline capacity rights all year for a limited number of cold winter days.

Typically, our firm contracts range in duration from 3 to 10 years. We work to stagger terms to maintain our ability to adjust the overall portfolio to meet changing market conditions. Our utilities have contracted for capacity that is predominately sourced from producing areas in the midcontinent and gulf coast regions, and they continue to evaluate capacity options that will provide long-term access to reliable and affordable natural gas supplies. We have and will continue to evaluate options to acquire capacity rights for shale gas being produced in close proximity to our service territories.

Given the number of agreements held by our utilities and the amount of capacity under contract, we make decisions as to the termination, extension or renegotiation of contracts every year. Slower demand and the growth in natural gas production from non-traditional supply basins have made the value assessment of capacity contracts more complex.

Supply Six of our utilities use asset management agreements with our wholly owned subsidiary, Sequent, for the primary purpose of reducing our utility customers' gas cost recovery rates through payments to the utilities by Sequent (for Atlanta Gas Light these payments are controlled by the Georgia Commission and utilized for infrastructure improvements and to fund heating assistance programs, rather than for a reduction to gas cost recovery rates). Under these asset management agreements, Sequent supplies natural gas to the utility and markets excess capacity to improve the overall cost of supplying gas to the utility customers. At this time, the utilities primarily purchase their gas from Sequent. The purchase agreements require Sequent to provide firm gas to our utilities. However, these utilities maintain the right and ability to make their own gas supply purchases. This right allows our utilities to make long-term supply arrangements if they believe it is in the best interest of their customers. Nicor Gas has not entered into an asset management agreement with Sequent or any other parties.

Each agreement with Sequent has either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without any annual minimum guarantee or a fixed fee. From the inception of these agreements in 2001 through 2013, Sequent has made sharing payments under these agreements totaling $225 million. The following table provides payments made by Sequent to our utilities under these agreements during the last three years.

	Total amount received			
In millions	**2013**	**2012**	**2011**	**Expiration Date**
Atlanta Gas Light	$ 6	$ 5	$ 9	March 2017
Virginia Natural Gas	4	3	9	March 2016
Florida City Gas	1	1	2	March 2015
Chattanooga Gas	1	1	3	March 2015
Elizabethtown Gas	6	5	9	March 2014 (1)
Total	$ 18	$ 15	$ 32	

(1) Discussions are underway with the New Jersey BPU and we expect a new agreement to be in place prior to the March 2014 expiration date.

Utility Regulation and Rate Design

Rate Structures Our utilities operate subject to regulations and oversight of the state regulatory agencies in each of the states served by our utilities with respect to rates charged to our customers, maintenance of accounting records and various service and safety matters. Rates charged to our customers vary according to customer class (residential, commercial or industrial) and rate jurisdiction. These agencies approve rates designed to provide us the opportunity to generate revenues to recover all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return for our shareholders. Rate base generally consists of the original cost of the utility plant in service, working capital and certain other assets, less accumulated depreciation on the utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

The natural gas market for Atlanta Gas Light was deregulated in 1997. Accordingly, Marketers, rather than a traditional utility, sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. As a result of operating in a deregulated environment, Atlanta Gas Light's role includes:

- distributing natural gas for Marketers;
- constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks;
- reading meters and maintaining underlying customer premise information for Marketers; and
- planning and contracting for capacity on interstate transportation and storage systems.

Atlanta Gas Light earns revenue by charging rates to its customers based primarily on monthly fixed charges that are set by the Georgia Commission and periodically adjusted. The Marketers add these fixed charges to customer bills. This mechanism, called a straight-fixed-variable rate design, minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent.

With the exception of Atlanta Gas Light, the earnings of our regulated utilities can be affected by customer consumption patterns that are largely a function of weather conditions and price levels for natural gas. Specifically, customer demand substantially increases during the Heating Season when natural gas is used for heating purposes. We have various mechanisms, such as weather normalization mechanisms and weather derivative instruments in place at most of our utilities, which limit our exposure to weather changes within typical ranges in these utilities' respective service areas.

All of our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover all of the costs prudently incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need nor utilize a traditional natural gas cost recovery mechanism. However, Atlanta Gas Light does maintain inventory for the Marketers in Georgia and recovers the cost of this gas through recovery mechanisms approved by the Georgia Commission specific to Georgia's deregulated market. In addition to natural gas recovery mechanisms, we have other cost recovery mechanisms, such as regulatory riders, which vary by utility but allow us to recover certain costs, such as those related to environmental remediation and energy efficiency plans.

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In traditional rate designs, utilities recover a significant portion of their fixed customer service and pipeline infrastructure costs based on assumed natural gas volumes used by our customers. Three of our utilities have decoupled regulatory mechanisms in place that encourage conservation. We believe that separating, or decoupling, the recoverable amount of these fixed costs from the customer throughput volumes, or amounts of natural gas used by our customers, allows us to encourage our customers' energy conservation and ensures a more stable recovery of our fixed costs. The following table provides regulatory information for our six largest utilities.

($ in millions)	**Nicor Gas** (9)	**Atlanta Gas Light**	**Virginia Natural Gas**	**Elizabethtown Gas**	**Florida City Gas**	**Chattanooga Gas**
Authorized return on rate base (1)	8.09%	8.10%	7.38%	7.64%	7.36%	7.41%
Estimated 2013 return on rate base (2)	7.55%	8.56%	6.85%	8.42%	5.90%	8.53%
Authorized return on equity (1)	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2013 return on equity (2)	8.77%	11.65%	10.19%	11.92%	10.57%	12.46%
Authorized rate base % of equity (1)	51.07%	51.00%	45.36%	47.89%	36.77%	46.06%
Rate base included in 2013 return on equity (2)	$ 1,486	$ 2,226	$ 596	$ 496	$ 166	$ 89
Weather normalization (3)			✓	✓		✓
Decoupled or straight-fixed-variable rates (4)		✓	✓			✓
Regulatory infrastructure program rates (5)	✓	✓	✓	✓		
Bad debt rider (6)	✓		✓			✓
Synergy sharing policy (7)		✓				
Energy efficiency plan (8)	✓		✓	✓	✓	✓
Last decision on change in rates	2009	2010	2011	2009	N/A	2010

(1) The authorized return on rate base, return on equity and percentage of equity were those authorized as of December 31, 2013.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction. Rate base includes investments in regulatory infrastructure programs.
(3) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer-than-normal and decreasing amounts charged when weather is colder-than-normal.
(4) Decoupled and straight-fixed-variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers. Virginia Natural Gas' request for approval of a decoupled rate design became effective June 1, 2013.
(5) Includes programs that update or expand our distribution systems and liquefied natural gas facilities. Available in Illinois, but not yet effective.
(6) Involves the recovery (refund) of the amount of bad debt expense over (under) an established benchmark expense. Virginia Natural Gas and Chattanooga Gas recover the gas portion of bad debt expense through PGA mechanisms.
(7) Involves the recovery of 50% of net synergy savings achieved on mergers and acquisitions.
(8) Includes the recovery of costs associated with plans to achieve specified energy savings goals.
(9) In connection with the December 2011 Nicor merger, we agreed to (i) not initiate a rate proceeding for Nicor Gas that would increase base rates prior to December 2014, (ii) maintain 2,070 full-time equivalent employees involved in the operation of Nicor Gas for a period of three years and (iii) maintain the personnel numbers in specific areas of safety oversight of the Nicor Gas system for a period of five years.

Current Regulatory Proceedings

Nicor Gas In June 2013, in connection with the PBR plan, the Illinois Commission issued an order requiring us to refund $72 million to Nicor Gas' current customers over a 12-month period. In July 2013, Nicor Gas began refunding customers through our purchased gas adjustment mechanism, which is based on natural gas throughput. Through December 31, 2013, $29 million was refunded. For more information on the PBR plan, see Note 11 to our consolidated financial statements under Item 8 herein.

In July 2013, Illinois enacted legislation that will allow Nicor Gas to provide more widespread safety and reliability enhancements to its system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average 4.0% of base rate revenues. We expect to submit a plan for approval by the Illinois Commission in mid-2014, to become effective in January 2015.

In July 2013, Illinois enacted legislation that provides a streamlined process to revise depreciation rates for natural gas utilities. On August 30, 2013, Nicor Gas filed a depreciation study with the Illinois Commission that proposed a composite depreciation rate of 3.07% compared to the prior composite rate of 4.10%. In October 2013, the Illinois Commission approved our proposed composite depreciation rate for Nicor Gas, which became effective as of the date the depreciation study was filed and had the effect of reducing our 2013 depreciation expense by $19 million. If applied to Nicor Gas' PP&E throughout 2013, the new composite depreciation rate would have resulted in a $53 million decrease in annual depreciation expense. The lower composite depreciation rate did not impact customer rates.

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.

Atlanta Gas Light In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve an imbalance of approximately 4.8 Bcf of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. We believe that any costs associated with resolving the imbalance are recoverable from Marketers. The resolution of this imbalance will be decided by the Georgia Commission and we are unable to predict the ultimate outcome.

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In accordance with an order issued by the Georgia Commission, where AGL Resources makes a business acquisition that reduces the costs allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a 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.

Virginia Natural Gas In accordance with Virginia's Natural Gas Conservation and Ratemaking Efficiency Act (CARE), Virginia Natural Gas filed for approval of its CARE plan with the Virginia Commission in December 2012. This plan includes a decoupling mechanism and authority to record accounting entries associated with such a mechanism. Our CARE plan has two principal components: (i) an Energy Conservation Plan component consisting of four cost-effective conservation and energy efficiency initiatives or programs plus a Community Outreach and Customer Education program; and (ii) a natural gas decoupling mechanism, Revenue Normalization Adjustment component and a rider which provides for a sales adjustment. In May 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.

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

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

Capital Projects

We continue to focus on capital discipline and cost control while moving ahead with projects and initiatives that we expect will have current and future benefits to us and our customers, provide an appropriate return on invested capital and ensure the safety, reliability and integrity of our utility infrastructure. Total capital expenditures incurred during 2013 for our distribution operations segment were $684 million. The following table and discussions provide updates on some of our larger capital projects under various programs at our distribution operations segment. These programs update or expand our distribution systems to improve system reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2014 are discussed in "Liquidity and Capital Resources".

Dollars in millions	**Utility**	**Expenditures in 2013**	**Expenditures since project inception**	**Miles of pipe installed**	**Year project began**	**Scheduled year of completion**
STRIDE program						
Pipeline replacement program (PRP) (1)	Atlanta Gas Light	$ 151	$ 833	2,708	1998	2013
Integrated System Reinforcement Program (i-SRP)	Atlanta Gas Light	27	251	n/a	2009	2017
Integrated Customer Growth Program (i-CGP)	Atlanta Gas Light	11	40	n/a	2010	2017
Integrated Vintage Plastic Replacement Program (i-VPR)	Atlanta Gas Light	5	5	29	2013	2017
Enhanced infrastructure program	Elizabethtown Gas	8	116	107	2009	2017
Accelerated infrastructure replacement program (SAVE)	Virginia Natural Gas	24	40	86	2012	2017
Total		$ 226	$ 1,285	2,930		

(1) The mileage disclosed represents miles of pipe that have been retired. We closed the PRP on December 31, 2013.

Atlanta Gas Light Our STRIDE program is comprised of i-SRP, i-CGP, PRP (which ended in 2013), and a new component, i-VPR. These infrastructure and replacement programs are used to update and expand distribution systems and liquefied natural gas facilities, improve system reliability and meet operations flexibility and growth. 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.

In December 2013, we received approval from the Georgia Commission for a new $260 million, four-year STRIDE program, $214 million of which will be for i-SRP related projects and $46 million of which will be for i-CGP related projects. The program will be funded through a monthly rider surcharge per customer of $0.48 beginning in January 2015, which will increase to $0.96 beginning in January 2016 and to $1.43 beginning in January 2017. This surcharge will continue through 2025.

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. In August 2013, the Georgia Commission approved i-VPR which includes the replacement of the first 756 miles of vintage plastic pipe over four years for $275 million. The program will be funded through a monthly rider surcharge per customer of $0.48 through December 2014, which will be increased to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016. This surcharge will continue through 2025. If the Commission elects to extend the i-VPR program beyond 2017, the remaining vintage plastic mains in our system potentially could be considered for replacement through the program over the next 15 - 20 years as it reaches the end of its useful life.

Elizabethtown Gas In August 2013, our request to extend the enhanced infrastructure program was approved by the New Jersey BPU. The approval allows for infrastructure investment of $115 million over four years, effective as of September 2013. Carrying charges on the additional capital spend will be accrued and deferred at a weighted average cost for capital of 6.65%. 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. Also in August 2013, the New Jersey BPU approved the recovery of prior accelerated infrastructure investments under this program through a permanent adjustment to base rates.

In March 2013, the BPU issued an order inviting the submission of proposals from utilities in New Jersey for infrastructure upgrades designed to protect utility infrastructure from future major storm events. In September 2013, in response to this request, Elizabethtown Gas filed for a Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program that will improve 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 In June 2012, the Virginia Commission approved Virginia Natural Gas' SAVE program, which involves replacing aging infrastructure as prioritized through Virginia Natural Gas' distribution integrity management program. SAVE was filed in accordance with a Virginia statute providing a regulatory cost recovery mechanism to recover the costs associated with certain infrastructure replacement programs. This is a five-year program that includes a maximum allowance for capital expenditure of $25 million per year, not to exceed $105 million in total. SAVE is subject to annual review by the Virginia Commission. We began recovering costs based on this program through a rate rider that became effective in August 2012. In May 2013, we filed our annual SAVE rate update detailing the first year performance and our expected future budget, which is subject to review and approval by the Virginia Commission. The rate update was approved with minor modifications by the Virginia Commission in July 2013 and became effective as of August 2013.

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 our current and former operating sites. As we continue to conduct the remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. These costs are primarily recovered through rate riders.

See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Critical Accounting Policies and Estimates" and Note 3 to our consolidated financial statements under Item 8 herein for additional information about our environmental remediation liabilities and efforts.

Retail Operations

Our retail operations segment serves approximately 620,000 natural gas commodity customers and 1.1 million service contracts. Companies within our retail operations segment include SouthStar and Pivotal Home Solutions.

SouthStar markets natural gas to residential, commercial and industrial customers, primarily in Georgia and Illinois, where we capture spreads between wholesale and retail natural gas prices. Additionally, we offer our customers energy-related products that provide for natural gas price stability and utility bill management. These products mitigate and/or eliminate the risks to customers of colder-than-normal weather and/or changes in natural gas prices. We charge a fee or premium for these services. Through our commercial operations, we optimize storage and transportation assets and effectively manage commodity risk, which enables us to maintain competitive retail prices and operating margin.

SouthStar is a joint venture owned 85% by us and 15% by Piedmont and is governed by an executive committee with equal representation by both owners. After considering the relevant factors we consolidate SouthStar in our financial statements. In September 2013, we contributed our wholly owned Illinois retail energy subsidiaries to the SouthStar joint venture. Piedmont contributed $22.5 million in cash to SouthStar to maintain its 15% ownership interest. In connection with the contribution of our Illinois retail energy businesses, we provided certain limited protections to Piedmont regarding the value of the contributed businesses related to goodwill and other intangible assets. See Note 10 to our consolidated financial statements under Item 8 herein for more information.

In June 2013, our retail operations segment acquired approximately 33,000 residential and commercial relationships in Illinois for $32 million. The transaction significantly increases the size of our retail energy customer portfolio in Illinois with minimal incremental operating expenses.

Pivotal Home Solutions provides a suite of home protection products and services that offer homeowners additional financial stability regarding their energy service delivery, systems and appliances. We offer a proprietary line of customizable home warranty and energy efficiency plans that can be co-branded with utility and energy companies. Currently, Pivotal Home Solutions serves customers in 17 states primarily in Illinois, Indiana and Ohio.

In January 2013, our retail operations segment acquired approximately 500,000 service contracts and certain other assets for $122 million. We believe this acquisition will provide an enhanced platform for growth and continued expansion of this business in a number of key markets.

Competition and Operations Our retail operations business competes with other energy marketers to provide natural gas and related services to customers in the areas that they operate. In the Georgia market, SouthStar operates as Georgia Natural Gas and is the largest of 12 Marketers, with average customers of nearly 500,000 over the last three years and market share of approximately 31%.

In recent years, increased competition and the heavy promotion of fixed-price plans by SouthStar’s competitors have resulted in increased pressure on retail natural gas margins. In response to these market conditions, SouthStar’s residential and commercial customers have been migrating to fixed-price plans, which, combined with increased competition from other Marketers, has impacted SouthStar’s customer growth as well as margins.

In addition, similar to our natural gas utilities, our retail operations businesses face competition based on customer preferences for natural gas compared to other energy products, primarily electricity, and the comparative prices of those products. We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers.

SouthStar’s operations are sensitive to seasonal weather, natural gas prices, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar’s retail pricing strategies and the use of a variety of hedging strategies, such as the use of futures, options, swaps, weather derivative instruments and other risk management tools, help to ensure retail customer costs are covered to mitigate the potential effect of these issues and commodity price risk on its operations. For more information on SouthStar’s energy marketing and risk management activities, see Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Natural Gas Price Risk.”

Our retail operations business also experiences price, convenience and service competition from other warranty and heating, ventilation, and air conditioning (HVAC) companies. These businesses also bear risk from potential changes in the regulatory environment.

Wholesale Services

Our wholesale services segment consists of our wholly owned subsidiary Sequent that engages in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing of natural gas across the U.S. and Canada. Wholesale services utilizes a portfolio of natural gas storage assets, contracted supply from all of the major producing regions, as well as contracted storage and transportation capacity to provide these services to its customers. Its customers consist primarily of electric and natural gas utilities, power generators and large industrial customers. Our logistical expertise enables us to provide our customers with natural gas from the major producing regions and market hubs. We also leverage our portfolio of natural gas storage assets and contracted natural gas supply, transportation and storage capacity to meet our delivery requirements and customer obligations at competitive prices.

Wholesale services' portfolio of storage and transportation capacity enables us to generate additional operating margin by optimizing the contracted assets through the application of our wholesale market knowledge and risk management skills as opportunities arise. These asset optimization opportunities focus on capturing the value from idle or underutilized assets, typically by participating in transactions that take advantage of volatility in pricing differences between varying geographic locations and time horizons (location and seasonal spreads) within the natural gas supply, storage and transportation markets to generate earnings. We seek to mitigate the commodity price and volatility risks and protect our operating margin through a variety of risk management and economic hedging activities.

In May 2013, we sold Compass Energy, which served primarily commercial and industrial customers, for an initial cash payment of $12 million, which resulted in an $11 million pre-tax gain ($5 million net of tax). 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 would be received from the buyer over a five-year earn out period based upon the financial performance of Compass Energy.

Competition and operations Wholesale services competes for asset management, long-term supply and seasonal peaking service contracts with other energy wholesalers, often through a competitive bidding process. We are able to price competitively by utilizing our portfolio of contracted storage and transportation assets and by renewing and adding new contracts at prevailing market rates. We will continue to broaden our market presence where our portfolio of contracted storage and transportation assets provides us a competitive advantage, as well as continue our pursuit of additional opportunities with power generation companies located in the areas of the country in which we operate. We are also focused on building our fee-based services in part to have a source of operating margin that is less impacted by volatility in the marketplace.

We view our wholesale margins from two perspectives. First, we base our commercial decisions on economic value for both our natural gas storage and transportation transactions. For our natural gas storage transactions, economic value is determined based on the net operating revenue to be realized at the time the physical gas is withdrawn from storage and sold and the derivative instrument used to economically hedge natural gas price risk on the physical storage that is settled. Similarly, for our natural gas transportation transactions, economic value is determined based on the net operating revenue to be realized at the time physical gas is purchased, transported, and sold utilizing our transportation capacity along with the settlement value associated with any derivative instruments.

The second perspective is the values reported in accordance with GAAP and encompassing periods prior to and in the period of physical withdrawal and sale of inventory or purchase, transportation and sale of natural gas. We enter into derivatives to hedge price risk prior to when the related physical storage withdrawal or transportation transactions occur based upon our commercial evaluation of future market prices. The reported GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value and prior to the period of the related physical storage and transportation transactions. The change in fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. This results in reported earnings volatility during the interim periods, however, the expected margin based upon the hedged economic value is ultimately realized in the period natural gas is physically withdrawn from storage or transported and sold at market prices and the related hedging instruments are settled.

For our natural gas storage portfolio, we purchase natural gas for storage when the current market price we pay plus the cost for transportation, storage and financing is less than the market price we anticipate we could receive in the future. We attempt to mitigate substantially all of the commodity price risk associated with our storage portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or OTC derivatives in forward months to substantially lock in the operating revenue that we will ultimately realize when the stored gas is actually sold.

We account for natural gas stored in inventory differently than the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. The natural gas that we purchase and inject into storage is accounted for at the LOCOM value. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in wholesale services reported results, even though the expected net operating revenue and locked-in economic value is essentially unchanged since the date the transactions were initiated. These accounting timing differences also affect the comparability of wholesale services period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year.

For our natural gas transportation portfolio, we enter into transportation capacity contracts with interstate and intrastate pipelines for the delivery of natural gas between receipt and delivery points in future periods. We purchase natural gas for transportation when the market price we pay for gas at a receipt point plus the cost of transportation capacity required to deliver the gas to the delivery point is less than the sales price at the delivery point. The difference between the price at the receipt point and the delivery point is the transportation basis or location spread. Similar to our storage transactions, we attempt to mitigate the commodity price risk associated with our transportation portfolio by using derivative instruments to reduce the risk associated with future changes in the price of natural gas at the receipt and delivery points. We utilize futures contracts or OTC derivatives to hedge both the commodity price risk relative to the market price at the receipt point and the market price at the delivery point to substantially lock in the operating revenue that we will ultimately realize once the natural gas is received, delivered and sold.

Volatility in the natural gas market arises from a number of factors, such as weather fluctuations or changes in supply or demand for natural gas in different regions of the country. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. During 2013, we experienced increased price volatility brought on by colder weather and supply constraints in the Northeast corridor, which enabled us to capture value under these market conditions. During 2012 and 2011, the volatility of daily Henry Hub spot market prices for natural gas in the U.S. was significantly lower than it had been for several prior years. This was the result of a robust natural gas supply, mild weather and ample storage.

It is possible the current market conditions may not continue and that natural gas prices will remain low for an extended period based on current levels of excess supply relative to market demand for natural gas, in part due to abundant sources of shale natural gas reserves, particularly in the Marcellus Shale producing region where Sequent has natural gas receipt requirements, and the lack of demand growth by commercial and industrial enterprises. However, as economic conditions improve, the demand for natural gas may increase, natural gas prices could rise and higher volatility could return to the natural gas markets. Consequently, we continue to reposition Sequent's business model with respect to fixed costs and the types of contracts pursued and executed.

Our natural gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. Additionally, our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs.

Sequent's expected natural gas withdrawals from storage and expected recovery of hedge losses associated with Sequent's transportation portfolio are presented in the following tables, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Sequent's expected net operating revenues exclude storage and transportation demand charges, as well as other variable fuel, withdrawal, receipt and delivery charges, but are net of the estimated impact of profit sharing under our asset management agreements. Further, the amounts that are realizable in future periods are based on the inventory withdrawal schedule, planned physical flow of natural gas between the transportation receipt and delivery points and forward natural gas prices at December 31, 2013. A portion of Sequent's storage inventory and transportation capacity is economically hedged with futures contracts, which results in realization of substantially fixed net operating revenues, timing notwithstanding.

In Bcf	**Storage schedule** (WACOG $3.42)	**Expected net operating revenues** *(in millions)*
First quarter - 2014	35	$ 26
Second quarter - 2014	1	2
Total at December 31, 2013	36	$ 28
Total at December 31, 2012	51	$ 27

For the year ended December 31, 2013, we have recorded $16 million in losses associated with the hedging of our storage position, compared to $14 million in storage hedge gains the same period last year. These hedge losses primarily relate to rising gas prices during the fourth quarter of 2013. If Sequent's storage withdrawals associated with existing inventory positions are executed as planned, it expects net operating revenues from storage withdrawals of $28 million in 2014. This could change as Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate.

The net operating revenues expected to be generated from the physical withdrawal of natural gas from storage do not reflect the earnings impact related to the movement in our hedges to lock in the forward location spread for the delivery of natural gas between two transportation delivery points associated with our transportation capacity portfolio.

For the year ended December 31, 2013, we have recorded $73 million in losses associated with the hedging of our transportation portfolio, or $70 million higher hedge losses as compared to the same period last year. These hedge losses are the result of widening transportation basis spreads associated with colder-than-normal weather, higher demand during the second half of 2013 and supply constraints experienced at natural gas receipt and delivery points throughout the Northeast corridor. These losses primarily relate to forward transportation and commodity positions for 2014, during which we expect to physically flow natural gas between the hedged transportation receipt and delivery points and utilize the contracted transportation capacity. The following table shows the periods associated with the transportation hedge losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the hedge losses recognized in 2013.

In millions	**Expected net operating revenues**
2014	$ 63
2015	7
2016 and thereafter	3
Total at December 31, 2013	$ 73
Total at December 31, 2012	$ 3

The unrealized storage and transportation hedge losses do not change the underlying economic value of our storage and transportation positions, and based on current expectations will largely be reversed in 2014 when the related transactions occur and are recognized. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Natural Gas Price Risk."

Midstream Operations

Our midstream operations segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability underground natural gas storage assets in the Gulf Coast region of the U.S. and in northern California. While this business can generate additional revenue during times of peak market demand for natural gas storage services, our natural gas storage facilities have a portfolio of short, medium and long-term contracts at fixed market rates. The following table shows the working gas capacity and firm subscription amounts by storage facility as of December 31, 2013.

				Subscribed (1)	
In Bcf	**Location**	**Type**	**Working Gas Capacity**	**Amount**	**%**
Jefferson Island (2) (3)	Louisiana	Salt-dome	7.3	5.6	77%
Golden Triangle (3)	Texas	Salt-dome	13.5	2.0	15%
Central Valley (4)	California	Depleted field	11.0	3.0	27%
Total			31.8	10.6	33%

(1) The amount and percentage of firm capacity under subscription does not include 3.5 Bcf of capacity subscribed by Sequent at December 31, 2013.
(2) Regulated by the Louisiana Department of Natural Resources.
(3) Regulated by the FERC.
(4) Regulated by the California Commission.

Sawgrass Storage This 50% owned joint venture between us and a privately held energy exploration and production company was granted certification from 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. Given the current storage market conditions and the need for additional storage capacity in the future, in December 2013 the joint venture decided to terminate 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. For more information about our investment in Sawgrass Storage, see Note 10 to the consolidated financial statements under Item 8 herein.

Magnolia Enterprise Holdings, Inc. This wholly owned subsidiary operates a pipeline that provides our Georgia customers access to LNG from the Elba Island terminal near Savannah, Georgia. The pipeline was completed in November 2009 and provides diversification of natural gas sources and increased reliability of service in the event that supplies coming from other supply sources are disrupted.

Competition and operations Our natural gas storage facilities primarily compete with natural gas facilities in the Gulf Coast region of the U.S. as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Salt caverns have also been leached from bedded salt formations in the Northeastern and Midwestern states. Competition for our Central Valley storage facility primarily consists of storage facilities in northern California and western North America.

The market fundamentals of the natural gas storage business are cyclical. The abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. In 2013, expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to continue in 2014 as compared to historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy improves, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. We believe our storage assets are strategically located to benefit from these expected improvements in market fundamentals, including the overall growth in the natural gas market and there are significant barriers to develop new storage facilities, including time of construction and other costs, federal, state and local permitting and approvals and suitable and available sites, to capitalize on these expected improvements in market conditions.

Cargo Shipping

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

Tropical Shipping is a transporter of containerized cargo and provides southbound scheduled services from the U.S. and Canada to 25 ports in the Bahamas and the Caribbean, interisland service between several of the Caribbean ports and operates from St. Thomas and St. Croix as its hubs in the Caribbean. In addition, it provides northbound shipments from those islands to the U.S. and Canada. Other related services, such as inland transportation and cargo insurance, are also provided by Tropical Shipping or its other subsidiaries and affiliates.

Generally, approximately 70% - 75% of Tropical Shipping's total volumes shipped are in the southbound market, 15% - 20% interisland and 5% - 10% northbound. Tropical Shipping measures volumes and capacity of vessels and containers in TEU's. Details of Tropical Shipping's properties are discussed in Item 2, "Properties" under the caption "Vessels and shipping containers."

Seven Seas is a Florida domestic insurance corporation that provides cargo insurance policies mainly between Tropical Shipping and its customers. During 2013, 66% of Seven Seas' revenues were generated from Tropical Shipping's customers. Policy coverage is from the point when the cargo leaves the shipper's possession to the point when the customer takes delivery.

Triton is a full-service global leasing company and an owner-lessor of marine intermodal cargo containers. Profits and losses are generally allocated to investors' capital accounts in proportion to their capital contributions. Our investment in Triton is accounted for under the equity method, and our share of earnings is reported within "Other Income" on our Consolidated Statements of Income. For more information about our investment in Triton, see Note 10 to the consolidated financial statements under Item 8 herein.

Competition and Operations Cargo shipping has five main competitors that serve the same major transportation areas. Our volumes shipped increased during 2013, but our profitability on those volumes continued to be adversely affected by competitive shipping rates.

Tropical Shipping's operating results are cyclical and very much aligned with the level of global gross domestic product, tourism and the cost of fuel. Overall, the economies of the Bahamas and the Virgin Islands are highly dependent on tourism from the U.S. and the Caribbean's Windward and Leeward Island economies primarily depend on tourism from Europe. Fuel price volatility also impacts our earnings. Bunker surcharge rates are charged to customers and are used to mitigate the fluctuations in fuel transportation costs. In 2014, we expect similar general market challenges as those experienced in 2013 with respect to overall levels of competition and related impacts on shipping volumes and rate pressure.

Seven Seas generates revenues from premiums received on insurance policies subscribed to primarily by customers of Tropical Shipping. Seven Seas' results depend on its ability to generate revenues from the premiums and to manage risk.

Other

Our other segment primarily includes our non-operating business units. AGL Services Company is a service company we established to provide certain centralized shared services to our operating segments. We allocate substantially all of AGL Services Company's operating expenses and interest costs to our operating segments in accordance with state regulations. Our EBIT results include the impact of these allocations to the various operating segments. However, merger-related costs were not allocated to our operating segments.

AGL Capital, our wholly owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities and other financing arrangements. This segment also includes intercompany eliminations for transactions between our operating business segments.

Employees

As of December 31, 2013, we had approximately 6,094 employees, 5,626 of whom were in the U.S.

The following table provides information about our natural gas utilities' collective bargaining agreements, which represent approximately 27% of our total employees.

	# of Employees	**Contract Expiration Date**
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19) (1)	1,351	February 2014
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50)	132	May 2015
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	172	November 2015
Total	1,655	

(1) Contract negotiations are ongoing; however, we do not expect a new contract to be finalized prior to the expiration of the current contract. We have a continuation agreement in place and do not expect this to result in a work stoppage.

We believe that we have a good working relationship with our unionized employees and there have been no work stoppages at Virginia Natural Gas, Elizabethtown Gas, or Nicor Gas since we acquired those operations in 2000, 2004, and 2011, respectively. As we have historically done, we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the Company and our employees. Our current collective bargaining agreements do not require our participation in multiemployer retirement plans and we have no obligation to contribute to any such plans.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and proxy statements, and amendments to those reports that we file with, or furnish to, the SEC are available free of charge at the SEC website http://www.sec.gov and at our website, www.aglresources.com, as soon as reasonably practicable after we electronically file such reports with, or furnish such reports to, the SEC. However, our website and any contents thereof should not be considered to be incorporated by reference into this document. We will furnish copies of such reports free of charge upon written request to our Investor Relations department. You can contact our Investor Relations department at:

AGL Resources Inc.
Investor Relations
P.O. Box 4569
Atlanta, GA 30302-4569
404-584-4000

In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for our 2014 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 14, 2014, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each committee of our Board of Directors are available on our website. We will furnish copies of such information free of charge upon written request to our Investor Relations department.

ITEM 1A. RISK FACTORS

Forward-Looking Statements

This report and the documents incorporated by reference herein contain “forward-looking statements.” These statements, which may relate to such matters as future earnings, growth, liquidity, supply and demand, costs, subsidiary performance, credit ratings, dividend payments, new technologies and strategic initiatives, often include words such as “anticipate,” “assume,” “believe,” “can,” “could,” “estimate,” “expect,” “forecast,” “future,” “goal,” “indicate,” “intend,” “may,” “outlook,” “plan,” “potential,” “predict,” “project,” “proposed,” “seek,” “should,” “target,” “would” or similar expressions. You are cautioned not to place undue reliance on forward-looking statements. While we believe that our expectations are reasonable in view of the information that we currently have, these expectations are subject to future events, risks and uncertainties, and there are numerous factors—many beyond our control—that could cause actual results to vary materially from these expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation, including any changes related to climate matters; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact on cost and timeliness of construction projects by government and other approvals, development project delays, adequacy of supply of diversified vendors, and unexpected change in project costs, including the cost of funds to finance these projects and our ability to recover our project costs from our customers; limits on pipeline capacity; the impact of acquisitions and divestitures, including recent acquisitions in our retail operations segment; our ability to successfully integrate operations that we have or may acquire or develop in the future; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions, including disruptions in the capital markets and lending environment; general economic conditions; uncertainties about environmental issues and the related impact of such issues, including our environmental remediation plans; the impact of the new depreciation rates for Nicor Gas; the impact of changes in weather, including climate change, on the temperature-sensitive portions of our business; the impact of natural disasters, such as hurricanes, on the supply and price of natural gas and on our cargo shipping business; acts of war or terrorism; the outcome of litigation; and the factors described in this Item 1A "Risk Factors" and the other factors discussed in our filings with the SEC.

There also may be other factors that we do not anticipate or that we do not recognize are material that could cause results to differ materially from expectations. Forward-looking statements speak only as of the date they are made. We expressly disclaim any obligation to update or revise any forward-looking statement, whether as a result of future events, new information or otherwise, except as required by law.

Risks Related to Our Business

Risks related to the regulation of our businesses could affect the rates we are able to charge, our costs and our profitability.

We are subject to regulation by federal, state and local regulatory authorities. In particular, at the federal level our businesses are regulated by the FERC. At the state level, our businesses are regulated by regulatory authorities in Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland.

These authorities regulate many aspects of our operations, including construction and maintenance of facilities, rights of way, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of costs associated with our regulatory infrastructure projects, including our pipeline replacement program and environmental remediation activities, energy efficiency programs, relationships with our affiliates, franchise agreements and carrying costs we charge Marketers selling retail natural gas in Georgia for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return and recover regulatory assets and liabilities recorded in accordance with authoritative guidance related to regulated operations depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return including the recovery of our regulatory assets and liabilities, or that the commissions will deem all costs, including capital costs, as prudently incurred.

We could incur significant compliance costs if we are required to adjust to new regulations. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. If we fail to comply with applicable regulations, whether existing or new, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities.

We are subject to environmental regulation and our costs to comply are significant. Any changes in existing environmental regulation could affect our results of operations and financial condition.

We are subject to extensive environmental regulation pursuant to a variety of federal, state and municipal laws and regulations. Such environmental regulation imposes, among other things, restrictions, liabilities and obligations associated with storage, transportation, treatment and disposal of MGP residuals and waste in connection with spills, releases and emissions of various substances into the environment. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Our current costs to comply with these laws and regulations are significant to our results of operations and financial condition. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to fines, penalties or interruptions in our operations that could be material to our results of operations.

We are generally responsible for liabilities associated with the environmental condition of the natural gas assets that we have operated, acquired or developed, regardless of when the liabilities arose and whether they are or were known or unknown. In addition, in connection with certain acquisitions and sales of assets, we may obtain, or be required to provide, indemnification against certain environmental liabilities. Before natural gas was widely available, we manufactured gas from coal and other fuels. Those manufacturing operations were known as MGPs, which we ceased operating in the 1950s. For more information regarding these obligations, see Note 11 to the consolidated financial statements under Item 8 herein.

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental laws and regulations also could be revised or reinterpreted, and new laws and regulations could be adopted or become applicable to us or our facilities. With the trend toward stricter standards, greater regulation, more extensive permit requirements and an increase in the number and types of assets operated by us subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

Our infrastructure improvement and customer growth may be restricted by the capital-intensive nature of our business.

We must construct additions and replacements to our natural gas distribution systems to continue the expansion of our customer base and improve system reliability, especially during peak usage. We also may need to construct expansions of our existing natural gas storage facilities or develop and construct new natural gas storage facilities. The cost of such construction may be affected by the cost of obtaining government and other approvals, project delays, adequacy of supply of vendors, vendor performance, or unexpected changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost, the projected construction schedule and the completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of such construction. As a result, we may be required to fund a portion of our cash needs through borrowings or the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or it may impair our ability to complete the expansions or development projects.

We may be exposed to certain regulatory and financial risks related to climate change and associated legislation and regulation.

Climate change is expected to receive increasing attention from the current federal administration, non-governmental organizations and legislators. Debate continues as to the extent to which our climate is changing, the potential causes of any change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

The EPA has begun using provisions of the Clean Air Act to regulate greenhouse gas emissions, including carbon dioxide. Thus far, EPA has imposed greenhouse gas regulations on automobiles and implemented new permitting requirements for the construction or modification of major stationary sources of greenhouse gas emissions, including natural gas-fired power plants.

In addition, President Obama issued a Presidential Memorandum on June 25, 2013, directing EPA to adopt performance standards to regulate greenhouse gas emissions from power plants. Specifically, the Presidential Memorandum directs EPA to propose standards for future power plants by September 20, 2013 and propose regulations and emission guidelines for modified, reconstructed, and existing power plants by June 1, 2014. The Presidential Memorandum directs EPA to finalize those regulations by June 1, 2015. States would be required to develop regulations implementing the EPA's guidelines by June 30, 2016. It also includes a wide variety of other initiatives designed to reduce greenhouse gas emissions, prepare for the impacts of climate change, and lead international efforts to address climate change.

The outcome of federal and state actions to address climate change could potentially result in new regulations, additional charges to fund energy efficiency activities or other regulatory actions, which in turn could:

- result in increased costs associated with our operations,
- increase other costs to our business,
- affect the demand for natural gas (positively or negatively), and
- impact the prices we charge our customers and affect the competitive position of natural gas.

Because natural gas is a fossil fuel with low carbon content, it is likely that future carbon constraints will create additional demand for natural gas, both for production of electricity and direct use in homes and businesses. The impact is already being seen in the power production sector due to both environmental regulations and low natural gas costs.

Any adoption by federal or state governments mandating a substantial reduction in greenhouse gas emissions could have far-reaching and significant impacts on the energy industry. We cannot predict the potential impact of such laws or regulations on our future consolidated financial condition, results of operations or cash flows.

Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Our gas distribution and storage activities involve a variety of inherent hazards and operating risks, such as leaks, accidents, including third party damages, and mechanical problems, which could cause substantial financial losses. These risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution and impairment of our operations, which in turn could lead to substantial losses to us. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The location of pipelines and storage facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from these risks. The occurrence of any of these events not fully covered by insurance could adversely affect our financial position and results of operations.

We face increasing competition, and if we are unable to compete effectively, our revenues, operating results and financial condition will be adversely affected, which may limit our ability to grow our business.

The natural gas business is highly competitive, increasingly complex, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our retail businesses is affected by competition from other energy marketers providing retail natural gas services in our service territories, most notably in Illinois and Georgia. Natural gas competes with other forms of energy. The primary competitive factor is price. Changes in the price or availability of natural gas relative to other forms of energy and the ability of end-users to convert to alternative fuels affect the demand for natural gas. In the case of commercial, industrial and agricultural customers, adverse economic conditions, including higher natural gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

Our retail operations segment markets fixed-price and fixed-bill contracts that protect customers against higher natural gas prices, or protect customers against both higher natural gas prices and colder weather. The sale of these fixed-price contracts may be adversely affected if natural gas prices are, or are perceived to be, low and stable. Our retail operations segment also faces risks in the form of price, convenience and service competition from other warranty and HVAC companies. Retail services also bears risk from potential changes in the regulatory environment.

Our wholesale services segment competes with national and regional full-service energy providers, energy merchants and producers and pipelines for sales based on our ability to aggregate competitively priced commodities with transportation and storage capacity. Some of our competitors are larger and better capitalized than we are and have more national and global exposure than we do. The consolidation of this industry and the pricing to gain market share may affect our operating margin. We expect this trend to continue in the near term, and the increasing competition for asset management deals could result in downward pressure on the volume of transactions and the related operating margin available in this portion of Sequent's business.

Our midstream operations segment competes with natural gas facilities in the Gulf Coast region of the U.S. as the majority of the existing and proposed high deliverability salt-dome natural gas storage facilities in North America are located in the Gulf Coast region. Competition for our Central Valley storage facility in northern California primarily consists of storage facilities in northern California and western North America. Storage values have declined over the past several years due to low gas prices and low volatility and we expect this to continue in 2014.

Our cargo shipping segment competes with international maritime companies. The current expansion of the Panama Canal, which is expected to be completed and open for commercial ship transit in 2015, may lead to increased competition as larger vessels may gain access to the Caribbean. In addition, the growing development of the global logistic environment has moved away from port-to-port operations and towards the combined transport supply chain of various combinations of road, rail, sea and inland waterways. Globally, this has resulted in the need to improve ship productivity, sometimes via third party ship management, development of hub and spoke systems, larger ships, faster ship turnaround time and increased use of technology. Additionally, there are increased pricing pressures and decreased shipping volumes for the islands that Tropical Shipping currently serves. Increased competition may affect our volumes, market share, pricing structure and operating margin. Tropical Shipping does not have fuel contracts, but reduces its fuel price risk through fuel surcharges. Tropical Shipping has five primary competitors that serve the same major areas, some of which are larger and better capitalized than we are and have more global exposure than we do.

Changes or downturns in the economy could adversely affect our customers and negatively impact our financial results.

The overall economy in the U.S. has a significant impact on the financial well-being of many households in the U.S. As a result, changes or downturns in the U.S. economy could cause our customers to use less gas in future Heating Seasons and it may become more difficult for them to pay their natural gas bills. This may slow collections and lead to higher-than-normal levels of accounts receivables, bad debt and financing requirements. Sales to large industrial customers may be impacted by economic downturns. The manufacturing industry in the U.S. is subject to changing market conditions including international competition, fluctuating product demand and increased costs and regulation.

Tropical Shipping's business consists primarily of the shipment of building materials, food and other necessities from the U.S. and Canada to developers, distributors and residents in the Bahamas and the Caribbean region, as well as tourist-related shipments intended for use in hotels, resorts and on cruise ships. As a result, Tropical Shipping's results of operations, cash flows and financial condition can be significantly affected by adverse general economic conditions in the U.S., Bahamas, Caribbean region and Canada. Also, a shift in buying patterns that results in such goods being sourced directly from other parts of the world, including China and India, rather than the U.S. and Canada, could significantly affect Tropical Shipping's results of operations, cash flows and financial condition.

A significant portion of our accounts receivable is subject to collection risks, due in part to a concentration of credit risk at Nicor Gas, Atlanta Gas Light, SouthStar and Sequent.

Nicor Gas and Sequent often extend credit to their counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Nicor Gas and Sequent are exposed to the risk that they may not be able to collect amounts owed to them. If the counterparty to such a transaction fails to perform and any collateral Nicor Gas or Sequent has secured is inadequate, they could experience material financial losses.

Further, Sequent has a concentration of credit risk, which could subject a significant portion of its credit exposure to collection risks. Most of this concentration is with counterparties that are either load-serving utilities or end-use customers that have supplied some level of credit support. Default by any of these counterparties in their obligations to pay amounts due to Sequent could result in credit losses that would negatively impact our wholesale services segment.

We have accounts receivable collection risks in Georgia due to a concentration of credit risks related to the provision of natural gas services to Marketers. At December 31, 2013, Atlanta Gas Light provided services to 12 certificated and active Marketers in Georgia. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. AGL Resources provides a guarantee to Atlanta Gas Light as security support for SouthStar. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay. For more information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Credit Risk" herein.

The asset management arrangements between Sequent and our local distribution companies, and between Sequent and its non-affiliated customers, may not be renewed or may be renewed at lower levels, which could have a significant impact on Sequent's business.

Sequent currently manages the storage and transportation assets of our affiliates Atlanta Gas Light, Virginia Natural Gas, Elizabethtown Gas, Florida City Gas, Chattanooga Gas and Elkton Gas. The profits it earns from the management of those assets with these affiliates are shared with their respective customers and for Atlanta Gas Light with the Georgia Commission's Universal Service Fund, with the exception of Chattanooga Gas and Elkton Gas where Sequent is assessed annual fixed-fees. Entry into and renewal of these agreements are subject to regulatory approval. The agreements with Elizabethtown Gas and Elkton Gas expire in March 2014 and we cannot predict whether such agreements will be renewed or the terms of such renewal.

Sequent also has asset management agreements with certain non-affiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms. Sustained low natural gas prices could reduce the demand for these types of asset management arrangements.

We are exposed to market risk and may incur losses in wholesale services, midstream operations and retail operations.

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at midstream operations and SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. For more information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Value-at-risk" herein.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect for wholesale services.

Although Sequent enters into various contracts to hedge the value of our energy assets and operations, the timing of the recognition of profits or losses on the hedges does not always correspond to the profits or losses on the item being hedged. The difference in accounting can result in volatility in Sequent's reported results, even though the expected operating margin is essentially unchanged from the date the transactions were initiated.

Changes in weather conditions may affect our earnings.

Weather conditions and other natural phenomena can have a large impact on our earnings. Severe weather conditions can impact our suppliers and the pipelines that deliver gas to our distribution system. Extended mild weather, during either the winter or summer period, can have a significant impact on demand for and cost of natural gas.

At Nicor Gas, approximately 50% of all usage is for space heating and approximately 75% of the usage and revenues occur from October through March. Weather fluctuations have the potential to significantly impact year-to-year comparisons of operating income and cash flow. We estimate that a 100 degree-day variation from normal weather of 5,729 Heating Degree Days impacts Nicor Gas' margin, net of income taxes, by approximately $1 million under its current rate structure. 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 more information, see Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Natural gas price volatility" and the subheading "Hedges" and Note 2 to the consolidated financial statements under Item 8 herein.

We have WNA mechanisms for Virginia Natural Gas, Elizabethtown Gas and Chattanooga Gas that partially offset the impact of unusually cold or warm weather on residential and commercial customer billings and on our operating margin. At Elizabethtown Gas we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10.3%.

These WNA regulatory mechanisms are most effective in a reasonable temperature range relative to normal weather using historical averages. The protection afforded by the WNA depends on continued regulatory approval. The loss of this continued regulatory approval could make us more susceptible to weather-related earnings fluctuations.

We also have decoupled, including straight-fixed-variable, rate designs at Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas, which allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers. For more information, see Item 1, "Business" under the caption "Rate Structures" herein.

Changes in weather conditions also may impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to stabilize the impact on its operating margin in the event of warmer or colder-than-normal weather in the winter months. However, these instruments do not fully protect SouthStar's earnings from the effects of unusually warm or cold weather.

Wholesale services' earnings are impacted by changes in weather conditions as weather impacts the demand for natural gas and volatility in the natural gas market. The volatility of natural gas commodity prices has a significant impact on our customer rates, our long-term competitive position against other energy sources and the ability of our wholesale services segment to capture value from location and seasonal spreads. The volatility of natural gas prices in 2013 was higher relative to 2011 and 2012 due to colder weather and supply constraints in the Northeast corridor but relative to periods prior to 2011, generally it was significantly lower in part due to mild hurricane seasons and mild summer and winter weather. Through the acquisition of natural gas and hedging of natural gas prices, wholesale services reduces the risk to its results of operations, cash flows and financial condition.

Tropical Shipping's operations are affected by weather conditions in Florida, Canada, the Bahamas and Caribbean regions. During hurricane season in the summer and fall, Tropical Shipping may be subject to revenue loss, higher operating expenses, business interruptions, delays, and ship, equipment and facilities damage which could adversely affect Tropical Shipping's results of operations, cash flows and financial condition. In addition, Seven Seas' results of operations, cash flows and financial condition may be adversely affected due to increased insured losses relating to claims arising from hurricane-related events.

Our retail energy businesses in Illinois, Nicor Solutions and Nicor Advanced Energy, offer utility-bill management products that mitigate and/or eliminate the risks to customers of variations in weather and we hedge this risk to reduce any adverse effect to our results of operations, cash flows and financial condition.

A decrease in the availability of adequate pipeline transportation capacity due to weather conditions could reduce our revenues and profits. Our gas supply for our distribution operations, retail operations, wholesale services and midstream operations segments depends on availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation and storage service could reduce our normal interstate supply of gas or cause rates to fluctuate.

Our profitability may decline if the counterparties to Sequent's asset management transactions fail to perform in accordance with Sequent's agreements.

Sequent focuses on capturing the value from idle or underutilized energy assets, typically by executing transactions that balance the needs of various markets and time horizons. Sequent is exposed to the risk that counterparties to our transactions will not perform their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements, honor the underlying commitment at then-current market prices or return a significant portion of the consideration received for gas. In such events, we may incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

Inflation and increased gas costs could adversely impact our ability to control operating expenses and costs, increase our level of indebtedness and adversely impact our customer base.

Inflation has caused increases in certain operating costs. We attempt to control costs in part through implementation of best practices and business process improvements, many of which are facilitated through investments in information systems and technology. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to control operating expenses and investments within the amounts authorized to be collected in rates, and we intend to continue to do so. However, any inability by us to control our expenses in a reasonable manner would adversely influence our future results.

Rapid increases in the price of purchased gas could cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly, we would expect increases in our short-term debt, accounts receivable and bad debt expense.

Finally, higher costs of natural gas can cause our utility customers to conserve their use of our gas services or switch to other competing products. Higher natural gas costs may increase competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fueled equipment to equipment fueled by other energy sources.

The cost of providing retirement plan benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changes in liabilities as a result of updated demographics and assumptions. These changes may have a material adverse effect on our financial results.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics and assumptions, including longer life expectancy of beneficiaries and changes in health care cost trends. Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension plan assets. In these circumstances, we may be required to recognize an increased pension expense and a charge to our other comprehensive income to the extent that the actual return on assets in the pension fund is less than the expected return. We may be required to make additional contributions in future periods in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of The Pension Protection Act of 2006 (Pension Protection Act).

For more information, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Contractual Obligations and Commitments" and the subheading "Pension and Other Retirement Plans" and Note 6 to the consolidated financial statements under Item 8 herein.

Natural disasters, pandemic illness, material misconduct, terrorist activities and the potential for military and other actions could adversely affect our businesses.

Natural disasters may damage our assets and interrupt our business operations. Pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. An employee or third party may purposely, or inadvertently, fail to adhere to our policies and procedures or our policies and procedures may not be effective; this could result in the violation of a law or regulation, a material error or misstatement, damage to our reputation or the incurrence of substantial expense. The threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the U.S., and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited or may be insufficient. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

A work stoppage could adversely impact our results of operations, cash flows and financial condition.

Certain of our businesses are dependent upon employees who are represented by unions and are covered by collective bargaining agreements. These agreements may increase our costs, affect our ability to continue offering market-based salaries and benefits and limit our ability to implement efficiency-related improvements. Disputes with the unions could result in work stoppages that could impact the delivery of natural gas and other services, which could strain relationships with customers, vendors and regulators. We believe that we have a good working relationship with our unionized employees and we remain committed to work in good faith with the unions to renew or renegotiate collective bargaining agreements that balance the needs of the Company and our employees. For more information, see Item 1, "Business" under the caption "Employees" herein.

Changes in the laws and regulations regarding the sale and marketing of products and services offered by our retail operations segment could adversely affect our results of operations, cash flows and financial condition.

Our retail operations segment provides various energy-related products and services. These include sales of natural gas and utility-bill management services to residential and small commercial customers, and the sale, repair, maintenance and warranty of heating, air conditioning and indoor air quality equipment. The sale and marketing of these products and services are subject to various state and federal laws and regulations. Changes in these laws and regulations could impose additional costs on or restrict or prohibit certain activities, which could adversely affect our results of operations, cash flows and financial condition.

In 1997, Georgia enacted legislation allowing deregulation of gas distribution operations. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Marketers, including our majority-owned subsidiary, SouthStar, then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. We are not aware of any movement to do so, but it is possible that the legislature could reverse or amend portions of the deregulation process.

Changes in the laws and regulations regarding maritime activities offered by our cargo shipping segment could adversely affect our results of operations, cash flows and financial condition.

Tropical Shipping is subject to the International Ship and Port Facility Security Code and is also subject to the U.S. Maritime Transportation Security Act, both of which require extensive security assessments, plans and procedures. Tropical Shipping is also subject to the regulations of the Federal Maritime Commission, the Surface Transportation Board, as well as other federal agencies and local laws, where applicable. Additional costs that could result from changes in the rules and regulations of these regulatory agencies would adversely affect our results of operations, cash flows and financial condition.

Conservation could adversely affect our results of operations, cash flows and financial condition.

As a result of legislative and regulatory initiatives on energy conservation, we have put into place programs to promote additional energy efficiency by our customers. Funding for such programs is being recovered through cost recovery riders. However, the adverse impact of lower deliveries and resulting reduced margin could adversely affect our results of operations, cash flows and financial condition.

A security breach could disrupt our operating systems, shutdown our facilities or expose confidential personal information.

Security breaches of our information technology infrastructure, including cyber-attacks and cyber terrorism, could lead to system disruptions or generate facility shutdowns. If such an attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, such an attack could affect our ability to service our indebtedness, our ability to raise capital and our future growth opportunities.

Additionally, the protection of customer, employee and company data is critical to us. A breakdown or a breach in our systems that results in the unauthorized release of individually identifiable customer or other sensitive data could occur and have a material adverse effect on our reputation, operating results and financial condition. Such a breakdown or breach could also materially increase the costs we incur to protect against such risks. There is no guarantee that the procedures that we have implemented to protect against unauthorized access to secured data are adequate to safeguard against all data security breaches. We had no material security breaches in 2013.

We could be adversely affected by violations of the Foreign Corrupt Practices Act and similar worldwide anti-bribery laws.

Our international operations require us to comply with a number of U.S. and international laws and regulations, including those prohibiting certain payments to foreign officials. One of these laws, the Foreign Corrupt Practices Act (FCPA), generally prohibits U.S. companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or maintaining business. Although our policies require compliance with these laws and we maintain a compliance training program designed to avoid violations, controlling the actions of our employees and the representatives of our international operations is difficult and violations may occur. For a discussion of an investigation of a potential violation of such laws, see Item 3, “Legal Proceedings” herein. Violations of these laws, or allegations of such violations, could disrupt our business and result in a material adverse effect on our business and results of operations, cash flows and financial condition.

We may pursue acquisitions, divestitures and other strategic transactions, the success of which may impact our results of operations, cash flows and financial condition.

In the past, we have pursued acquisitions to complement or expand our business, divestures and other strategic transactions. Such future transactions are part of our general strategic objectives and may occur. If we identify an acquisition candidate, we may not be able to successfully negotiate or finance the acquisition or integrate the acquired businesses with our existing business and services. Acquisitions may result in potentially dilutive issuances of equity securities and the incurrence of debt and contingent liabilities, amortization expenses and substantial goodwill. Acquisitions may not be accretive to our earnings and may cause dilution to our earnings per share, which may negatively affect the market price of our common shares. We may be affected materially and adversely if we are unable to successfully integrate businesses that we acquire in an efficient and effective manner. Similarly, we may divest portions of our business, which may also have material and adverse effects.

We assess goodwill and indefinite-lived intangible assets for impairment at least annually and more frequently if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. We assess our long-lived assets, including finite-lived intangible assets, for impairment whenever events or circumstances indicate that an asset’s carrying amount may not be recoverable. To the extent the value of goodwill or long-lived assets become impaired, we may be required to incur impairment charges that could have a material impact on our results of operations. No impairment of goodwill was recorded as a result of our 2013 annual impairment testing as the fair value of each reporting unit was in excess of the carrying value. Additionally, no impairment of long-lived assets was recorded during 2013.

Since interest rates are a key component, among other assumptions, in the models used to estimate the fair values of our reporting units, as interest rates rise, the calculated fair values decrease and future impairments may occur. Further, the rates for contracting capacity at Jefferson Island, Golden Triangle and Central Valley are also key components in the models used to estimate their fair value. Consequently, a further decline in market fundamentals and the rates for contracting availability could result in future impairments. Our cargo shipping segment also has goodwill and assets subject to impairment testing and while conditions are improving in this segment it has been adversely impacted by the weak global economy. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, we cannot provide assurance that future analyses will not result in impairment. These assumptions and estimates include projected cash flows, current and future rates for contracted capacity, growth rates, weighted average cost of capital and market multiples. For additional information, see Item 7,"Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Critical Accounting Policies and Estimates" herein.

Failure to recruit, retain and train an appropriately qualified workforce could negatively impact our results of operations, cash flows and financial condition.

Our business is dependent on our ability to recruit, retain, and train employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skillsets to current and future needs, or the availability of outside resources may lead to operational challenges such as lack of resources, loss of knowledge, errors due to inexperience, or a lengthy training period. Our costs, including productivity and safety costs, costs to replace employees, and costs as a result of errors may increase. Failure to hire and adequately train employees, including the transfer of significant internal historical knowledge and expertise could adversely affect our ability to manage and operate our business.

Risks Related to Our Corporate and Financial Structure

We depend on our ability to successfully access the capital and financial markets. Any inability to access the capital or financial markets may limit our ability to execute our business plan or pursue improvements that we may rely on for future growth.

We rely on access to both short-term money markets (in the form of commercial paper and lines of credit) and long-term capital markets as a source of liquidity for capital and operating requirements not satisfied by the cash flow from our operations. If we are not able to access financial markets at competitive rates, our ability to implement our business plan and strategy will be negatively affected, and we may be forced to postpone, modify or cancel capital projects. Certain market disruptions may increase our cost of borrowing or affect our ability to access one or more financial markets. Such market disruptions could result from:

- adverse economic conditions;
- adverse general capital market conditions;
- poor performance and health of the utility industry in general;
- bankruptcy or financial distress of unrelated energy companies or Marketers;
- significant decrease in the demand for natural gas;
- adverse regulatory actions that affect our local gas distribution companies and our natural gas storage business;
- terrorist attacks on our facilities or our suppliers; or
- extreme weather conditions.

The amount of our working capital requirements in the near-term will primarily depend on the market price of natural gas and weather. Higher natural gas prices may adversely impact our accounts receivable collections and may require us to increase borrowings under our credit facilities to fund our operations.

While we believe we can meet our capital requirements from our operations and our available sources of financing, we can provide no assurance that we will continue to be able to do so in the future, especially if the market price of natural gas increases significantly in the near-term. The future effects on our business, liquidity and financial results due to market disruptions could be material and adverse to us, both in the ways described above, or in ways that we do not currently anticipate.

If we breach any of the financial covenants under our various credit facilities, our debt service obligations could be accelerated.

The AGL Credit Facility and the Nicor Gas Credit Facility contain financial covenants. If we breach any of the financial covenants under these agreements, our debt repayment obligations under them could be accelerated. In such event, we may not be able to refinance or repay all of our indebtedness, which would result in a material adverse effect on our business, results of operations and financial condition.

A downgrade in our credit rating could negatively affect our ability to access capital, or may require us to provide additional collateral to certain counterparties.

Our senior debt is currently assigned investment grade credit ratings. If the rating agencies downgrade our ratings, particularly below investment grade, it may significantly limit our access to the commercial paper market and our borrowing costs would increase. In addition, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources would likely decrease.

Additionally, if our credit rating by either S&P or Moody’s falls to non-investment grade status, we would be required to provide additional collateral to continue conducting business with certain customers. In December 2012, Fitch lowered the ratings of AGL Resources from A- to BBB+. There are no implications of this downgrade on our corporate funding ability or our ability to access the capital markets, nor does this downgrade trigger any collateralization requirements under our corporate guarantees. For additional credit rating and interest rate information, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Liquidity and Capital Resources” and Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Interest Rate Risk” herein.

We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense and adversely affect our earnings.

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. For additional information, see Item 7A, “Quantitative and Qualitative Disclosures About Market Risk” under the caption “Interest Rate Risk.” However, we may not structure these swap agreements in a manner that manages our risks effectively. If we are unable to do so, our earnings may be reduced. In addition, higher interest rates, all other things equal, reduce the earnings that we derive from transactions where we capture the difference between authorized returns and short-term borrowings.

We are a holding company and are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need.

A significant portion of our outstanding debt was issued by our wholly owned subsidiary, AGL Capital, which we fully and unconditionally guarantee. Since we are a holding company and have no operations separate from our investment in our subsidiaries, we are dependent on the net income and cash flows of our subsidiaries and their ability to pay upstream dividends or other distributions to meet our financial obligations and to pay dividends on our common stock. The ability of our subsidiaries to pay upstream dividends and make other distributions is subject to applicable state law and regulatory restrictions. In addition, Nicor Gas is not permitted to make money pool loans to affiliates. Refer to Item 5, “Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities” for additional information. Our subsidiaries are separate legal entities and have no obligation to provide us with funds.

The use of derivative contracts in the normal course of our business could result in financial losses that negatively impact our results of operations.

We use derivative instruments, including futures, options, forwards and swaps, to manage our commodity and financial market risks. We could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. In addition, derivative contracts entered for hedging purposes may not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative instruments can involve management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the reported fair value of these contracts.

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 introduced a comprehensive new framework for the regulation of OTC derivatives, including the requirement that certain OTC derivatives, or swaps, to be centrally cleared and executed through an exchange or other approved trading platform. The Dodd-Frank Act required various regulatory agencies, including the Commodity Futures Trading Commission and the SEC, to establish regulations for implementation of this requirement and many other provisions of the Dodd-Frank Act. A number of those regulations have been adopted and we have enacted new procedures and modified existing business practices and contractual arrangements to comply with such regulations. In addition, based on current interpretation, we were not considered to be a “swap dealer” or “major swap participant” in 2013 so we are exempt from the clearing, exchange trading and certain other requirements under the Dodd-

Frank Act. If these provisions were to apply to our derivative activities, we could be subject to higher costs for our derivative activities, including from higher margin requirements. In addition, implementation of, and compliance with, the OTC derivatives provisions of the Dodd-Frank Act by our swap counterparties could result in increased costs or additional collateral postings related to our derivative activities. We expect additional regulations to be issued, which should provide further clarity regarding the impact of this legislation on us, including any potential increased costs of our hedging activities.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part.

The AGL Credit Facility and the Nicor Gas Credit Facility contain cross-default provisions. Should an event of default occur under some of our debt agreements, we face the prospect of being in default under our other debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all of our outstanding obligations simultaneously.

Changes in taxation could adversely affect our results of operations, cash flows and financial condition.

Various tax and fee increases may occur in locations in which we operate. We cannot predict whether other legislation or regulation will be introduced, the form of any legislation or regulation, or whether any such legislation or regulation will be passed by the legislatures or other governmental bodies. New taxes or an increase in tax rates would increase tax expense and could adversely affect our results of operations, cash flows and financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We do not have any unresolved comments from the SEC staff regarding our periodic or current reports under the Securities Exchange Act of 1934, as amended.

ITEM 2. PROPERTIES

We consider our properties to be well maintained, in good operating condition and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by our segments. Substantially all of Nicor Gas' properties are subject to the lien of the indenture securing its first mortgage bonds. See Note 8 to our consolidated financial statements under Item 8 herein.

Distribution and transmission mains

Our distribution systems transport natural gas from our pipeline suppliers to our customers in our service areas. At December 31, 2013, our distribution operations segment owned approximately 80,500 miles of underground distribution and transmission mains. These distribution and transmission mains are located on easements or rights-of-way which generally provide for perpetual use.

Storage assets

Distribution Operations We own and operate eight underground natural gas storage facilities in Illinois with a total inventory capacity of about 150 Bcf, approximately 135 Bcf of which can be cycled on an annual basis. The system is designed to meet about 50% of the estimated peak-day deliveries and approximately 40% of its normal winter deliveries in Illinois. This level of storage capability provides us with supply flexibility, improves the reliability of deliveries and can mitigate the risk associated with seasonal price movements.

We have approximately 7.6 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own one propane storage facility in Virginia with a storage capacity of approximately 0.3 Bcf. The LNG plants and propane storage facility are used by our distribution operations segment to supplement natural gas supply during peak usage periods.

Midstream Operations We own three high-deliverability natural gas storage and hub facilities which are operated by our midstream operations segment. Jefferson Island operates a salt-dome storage facility in Louisiana currently consisting of two salt dome gas storage caverns with approximately 10 Bcf of total capacity and 7.3 Bcf of working gas capacity. Golden Triangle operates a salt-dome storage facility in Texas designed for 13.5 Bcf of working natural gas capacity and total cavern capacity of approximately 20 Bcf. Cavern 1, with 6 Bcf of working capacity, was completed and began commercial service in September 2010. Cavern 2, with 7.5 Bcf of working capacity, was completed and began commercial service in September 2012. Central Valley developed an underground natural gas storage facility in California with 11 Bcf of working natural gas capacity which was placed into commercial service in June 2012. In addition to the LNG facilities that support utility operations, we have placed into commercial operations an LNG facility purchased from the Trussville Utilities District in Alabama. This facility produces LNG for Pivotal LNG, a wholly owned subsidiary, to support its business of selling LNG as a substitute fuel in various market segments.

Vessels and shipping containers

Our cargo shipping segment regularly operates 11 owned vessels and 3 chartered vessels with a container capacity totaling approximately 6,750 TEUs. The owned vessels range in age from 3 - 37 years, and vary in length from 260 - 525 feet. In addition to the vessels, we own and/or lease containers, cargo-handling equipment, chassis and other equipment.

During the fourth quarter of 2013, we sold one of our vessels at approximately carrying value and replaced it with a chartered vessel that provides greater capacity and operational flexibility.

Offices

All of our segments own or lease office, warehouse and other facilities throughout our operating areas. We expect additional or substitute space to be available as needed to accommodate the expansion of our operations.

ITEM 3. LEGAL PROCEEDINGS

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities. In addition, we are party, as both plaintiff and defendant, to a number of lawsuits related to our business on an ongoing basis. Management believes that the outcome of all regulatory proceedings and litigation in which we are currently involved will not have a material adverse effect on our consolidated financial condition or results of operations.

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

For more information regarding our regulatory proceedings and litigation, see Note 11 to our consolidated financial statements under the caption "Litigation" under Item 8 herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Holders of Common Stock, Stock Price and Dividend Information

Our common stock is listed on the New York Stock Exchange under the ticker symbol GAS. At January 30, 2014, there were 20,598 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2013 and 2012 is as follows:

Quarter ended:	Sales price of common stock High	Sales price of common stock Low	Cash dividend per common Share	Quarter ended:	Sales price of common stock High	Sales price of common stock Low	Cash dividend per common share
March 31, 2013	$ 42.37	$ 38.86	$ 0.47	March 31, 2012 (1)	$ 42.88	$ 38.42	$ 0.36
June 30, 2013	44.85	41.21	0.47	June 30, 2012	40.29	36.59	0.46
September 30, 2013	47.00	41.94	0.47	September 30, 2012	41.95	38.45	0.46
December 31, 2013	49.31	44.56	0.47	December 31, 2012	41.71	36.90	0.46
			$ 1.88				$ 1.74

(1) As a result of the Nicor merger, our shareholders received a pro rata dividend of $0.0989 in the fourth quarter of 2011, which reduced the first quarter 2012 dividend by an equal amount. For presentation purposes the amount in the table was rounded to $0.10.

We have paid 264 consecutive quarterly dividends to our common shareholders beginning in 1948, historically four times each year: March 1, June 1, September 1 and December 1. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Cash Flow from Financing Activities - Dividends on Common Stock."

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, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants, and
- our ability to satisfy our obligations to any future preferred shareholders.

Under Georgia law, the payment of cash dividends to the holders of our common stock is limited to our legally available assets and subject to the prior payment of dividends on any outstanding shares of preferred stock. Our assets are not legally available for paying cash dividends if, after payment of the dividend:

- we could not pay our debts as they become due in the usual course of business, or
- our total assets would be less than our total liabilities plus, subject to some exceptions, any amounts necessary to satisfy (upon dissolution) the preferential rights of shareholders whose rights are superior to those of the shareholders receiving the dividends.

Securities Authorized for Issuance Under Equity Compensation Plans

See Part III, Item 12 “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” under the heading “Executive Compensation - Equity Compensation Plan Information.”

Issuer Purchases of Equity Securities

There were no purchases of our common stock by us or any affiliated purchasers during the three months ended December 31, 2013.

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ITEM 6. 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.

Dollars and shares in millions, except per share amounts	2013	2012 (1)	2011 (1)	2010	2009
Income statement data					
Operating revenues	$ 4,617	$ 3,922	$ 2,338	$ 2,373	$ 2,317
Operating expenses					
Cost of goods sold	2,332	1,791	1,097	1,164	1,142
Operation and maintenance (2)	999	921	501	497	497
Depreciation and amortization	418	415	186	160	158
Nicor merger expenses (2)	-	20	57	6	-
Taxes other than income taxes	193	165	57	46	44
Total operating expenses	3,942	3,312	1,898	1,873	1,841
Gain on sale of Compass Energy	11	-	-	-	-
Operating income	686	610	440	500	476
Other income (expense)	17	24	7	(1)	9
EBIT	703	634	447	499	485
Interest expenses	181	184	136	109	101
Earnings before income taxes	522	450	311	390	384
Income taxes	191	164	125	140	135
Net income	331	286	186	250	249
Less net income attributable to the noncontrolling interest	18	15	14	16	27
Net income attributable to AGL Resources Inc.	$ 313	$ 271	$ 172	$ 234	$ 222
Common stock data					
Diluted weighted average common shares outstanding	118.3	117.5	80.9	77.8	77.1
Diluted earnings per common share - attributable to AGL Resources Inc. common shareholders	$ 2.64	$ 2.31	$ 2.12	$ 3.00	$ 2.88
Dividends declared per common share (3)	$ 1.88	$ 1.74	$ 1.90	$ 1.76	$ 1.72
Dividend payout ratio	71%	75%	89%	58%	60%
Dividend yield (4)	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 (5)	$ 47.23	$ 39.97	$ 42.26	$ 35.85	$ 36.47
Market value (5)	$ 5,615	$ 4,711	$ 4,946	$ 2,800	$ 2,826
Statements of Financial Position data (5)					
Total assets	$ 14,656	$ 14,141	$ 13,913	$ 7,520	$ 7,079
Property, plant and equipment - net	8,781	8,347	7,900	4,405	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	3,676	3,435	3,339	1,836	1,819
Financial ratios (5)					
Debt	58%	59%	59%	60%	59%
Equity	42%	41%	41%	40%	41%
Total	100%	100%	100%	100%	100%
Return on average equity	8.8%	8.0%	6.6%	12.8%	12.7%

(1) Material changes from 2011 to 2012 are primarily due to the Nicor merger on December 9, 2011.
(2)

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

(3) 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 for the stub period, which accrued from November 19, 2011. This amount was rounded to $0.10 in the table.

(4) 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.

(5) 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, some of which are complementary to the distribution of natural gas along with other unregulated businesses. Our operating segments consist of the following five operating and reporting segments – distribution operations, retail operations, wholesale services, midstream operations and cargo shipping and one non-operating segment - other. These segments are consistent with how management views and operates our business. The following table provides certain information on our segments.

	EBIT			Assets			Capital Expenditures		
	2013	2012	2011	2013	2012	2011	2013	2012	2011
Distribution operations	83%	84%	92%	80%	80%	79%	91%	83%	85%
Retail operations	19	18	21	5	4	4	1	1	1
Wholesale services	(1)	-	1	8	9	9	-	-	-
Midstream operations	(1)	2	2	5	5	5	2	8	8
Cargo shipping	2	1	-	3	3	3	2	1	-
Other	(2)	(5)	(16)	(1)	(1)	-	4	7	6
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%

In 2013, our net income attributable to AGL Resources Inc. was $313 million an increase of $42 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 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.
- **Cargo Shipping**: Improve profitability, continue increasing vessel utilization, improve margin per TEU, prudently deploy capital investment and diligently manage operating costs.

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 Item 8 herein and Item 1, "Business".

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** (1)
Residential	$ 2,422	$ 2,011	$ 1,065
Commercial	696	656	467
Transportation	532	492	403
Shipping	365	342	19
Industrial	180	262	289
Other	422	159	95
Total operating revenues	$ 4,617	$ 3,922	$ 2,338

(1) 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, midstream operations and cargo shipping 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**	**2012**	**2011**
Operating revenues	$ 4,617	$ 3,922	$ 2,338
Cost of goods sold	(2,332)	(1,791)	(1,097)
Revenue tax expense (1)	(110)	(85)	(9)
Operating margin	2,175	2,046	1,232
Operating expenses (2) (3)	(1,610)	(1,501)	(744)
Revenue tax expense (1)	110	85	9
Gain on sale of Compass Energy	11	-	-
Nicor merger expenses (2)	-	(20)	(57)
Operating income	686	610	440
Other income	17	24	7
EBIT	703	634	447
Interest expenses	(181)	(184)	(136)
Earnings before income taxes	522	450	311
Income tax expenses	(191)	(164)	(125)
Net income	331	286	186
Less net income attributable to the noncontrolling interest	18	15	14
Net income attributable to AGL Resources Inc.	$ 313	$ 271	$ 172
Per common share data			
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders (4)	$ 2.64	$ 2.31	$ 2.12
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	$ 2.64	$ 2.46	$ 2.92

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

(2) 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).

(3) 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.

(4) Sale of Compass Energy increased basic and diluted EPS by $0.04 in 2013.

In 2013 our net income attributable to AGL Resources Inc. increased by $42 million or 15% compared to last year.

- 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.
- Our cargo shipping segment added to the favorable variance due primarily to higher volumes, partially offset by decreased average TEU rates.
- 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 $3 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 $27 million or 16% compared to 2012 primarily due to higher consolidated earnings, as previously discussed. Our effective tax rate was 38.0% in 2013 and 37.7% in 2012. Our estimated effective tax rate for 2014 is 37.9%.

In 2012 our net income attributable to AGL Resources Inc. increased by $99 million or 58% compared to 2011.

- The increase was primarily the result of increased operating income at distribution operations, retail operations and cargo shipping 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 $48 million or 35% 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 $39 million or 31% compared to the same period in 2011 primarily due to higher consolidated earnings. Our effective tax rate was 42.2% 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)	Year ended December 31,				2013 vs. 2012 colder (warmer)	2012 vs. 2011 colder (warmer)	2013 vs. normal colder (warmer)	2012 vs. normal colder (warmer)	2011 vs. normal colder (warmer)
	Normal (1)	**2013**	**2012**	**2011**					
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 vs. 2012 change		2012 vs. 2011 change	
	2013	**2012**	**2011**	**#**	**%**	**#**	**%**
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 the 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.

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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. Additionally, our cargo shipping segment measures the volume of shipments during the period in TEUs. In 2013 we successfully increased our number of TEUs and therefore the utilization of our containers and vessels. Our volume metrics are presented in the following table:

Volumes

	Year ended December 31,			**2013 vs. 2012**	**2012 vs. 2011**
Distribution operations (In Bcf)	**2013**	**2012**	**2011**	**% change**	**% change**
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%
Cargo shipping (TEU's - in thousands)					
Shipments	187	170	n/a	10%	n/a
	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	$ 1,660	$ 1,571	$ 963	$ 1,093	$ 1,048	$ 557	$ 582	$ 532	$ 412
Retail operations	294	247	168	157	131	75	137	116	93
Wholesale services	37	50	57	52	54	52	(4)	(3)	5
Midstream operations	41	46	37	46	38	28	(10)	10	9
Cargo shipping	143	134	7	140	137	8	12	8	-
Other	-	(2)	-	12	28	72	(14)	(29)	(72)
Consolidated	$ 2,175	$ 2,046	$ 1,232	$ 1,500	$ 1,436	$ 792	$ 703	$ 634	$ 447

(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 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.

The EBIT of our distribution operations, retail operations, wholesale services and cargo shipping 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.

Additionally, the revenues of our cargo shipping business are generally higher in the fourth quarter, as our customers require more tourist-related shipments as the hotels, resorts, and cruise ships typically have increased occupancy rates commencing in the fourth quarter and increasing further into the first quarter as consumer spending increases during traditional holiday periods. Revenues are impacted during the fourth quarter by peak season surcharges in effect from early October through December.

Approximately 66% of these segments' operating revenues and 69% of these segments' EBIT for the year ended December 31, 2013 were generated during the first and fourth quarters of 2013, and are reflected in our Consolidated Statements of Income for the quarters ended March 31, 2013 and December 31, 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	**$ 532**	**$ 412**
Operating margin		
Increased revenues from regulatory infrastructure programs, primarily at Atlanta Gas Light	31	15
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) margin from gas storage carrying amounts at Atlanta Gas Light	(5)	2
Other	(1)	1
Increase in operating margin	**89**	**608**
Operating expenses		
Increased (decreased) incentive compensation costs that reflect year over year performance	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	15	8
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	3	6
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	**45**	**491**
Increase in other income primarily from AFUDC equity from STRIDE Projects at Atlanta Gas Light	**6**	**3**
EBIT - current year	**$ 582**	**$ 532**

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	**$ 116**	**$ 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	-	59
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	**26**	**56**
EBIT - current year	**$ 137**	**$ 116**

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	84	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	**(13)**	**(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	2	2

(Decrease) increase in operating expenses	**(2)**	**2**
Gain on sale of Compass Energy	**11**	**-**
(Decrease) increase in other income	(1)	1
EBIT - current year	**$ (4)**	**$ (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.

Glossary

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 the 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	$ 127	$ 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	$ 37	$ 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.

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**

Cargo Shipping

Our cargo shipping segment's primary activity is transporting containerized cargo in the Bahamas and the Caribbean. Our cargo shipping segment also includes an equity investment in Triton, a cargo container leasing business. The cargo shipping business reported EBIT of $8 million for the year ended December 31, 2012, including $11 million EBIT from our investment in Triton. This was compared to an immaterial EBIT for the year ended December 31, 2011, as it only reflected the 22 days following the close of our merger with Nicor. For more information on our investment in Triton, see Note 10 to our consolidated financial statements under Item 8 herein.

In millions	2013
EBIT - prior year	**$ 8**
Operating margin	
TEU volume increased due to market share expansion and modest improvement in economic conditions in our service regions; leverage effect of volume increases on fuel expense	21
Decreased average TEU rates due to changes in cargo mix and competitive pressures, partially offset by general ocean freight rate increases	(10)
Other	(2)
Increase in operating margin	**9**
Operating expenses	
Increased operation and maintenance expenses	6
Decreased depreciation expense	(3)
Increase in operating expenses	**3**
Decrease from equity investment income in Triton	**(2)**
EBIT - current year	**$ 12**

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.

As of December 31, 2013 and 2012, we had $80 million of cash and short-term investments on our Consolidated Statements of Financial Position held by Tropical Shipping. This cash and investments are indefinitely reinvested offshore and not available for use by the Company or our other operations unless we repatriate a portion of Tropical Shipping’s earnings in the form of a dividend, which would be subject to U.S. income tax. See Note 12 to our consolidated financial statements under Item 8 herein for additional information on our income taxes.

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,” for additional information on items that could impact our liquidity and capital resource requirements.

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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	Term	Interest rate

			(in millions)	(in years)	
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):			
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	(26)	62	45
Cash and cash equivalents at beginning of period	131	69	24
Cash and cash equivalents at end of period	$ 105	$ 131	$ 69

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 $33 million, a net decrease in short-term investments of $12 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 cargo shipping, 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	120	96	93	54
Total	$ 790	$ 749	$ 782	$ 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 $749 million for the year ended December 31, 2013, compared to $782 million for the same period in 2012.The decrease of $33 million, or 4%, 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 $782 million for the year ended December 31, 2012, compared to $427 million for the same period in 2011.The increase of $355 million, or 83%, 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)	233	39	34	28	25	18	89
Asset management agreements (7)	19	8	5	4	2	-	-
Standby letters of credit, performance/surety bonds (8)	29	29	-	-	-	-	-
Other	15	6	3	3	2	1	-
Total	$ 5,493	$ 1,000	$ 724	$ 495	$ 314	$ 266	$ 2,694

(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 $899 million and regulatory liabilities were $1.7 billion. At December 31, 2012, our regulatory assets were $1.1 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 15% 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 these 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.

Glossary

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."

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.

Glossary

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 $216 million of deferred tax assets ($147 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 $1,800 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with natural gas prices, interest rates, credit and fuel prices. Natural gas price risk results from changes in the fair value of natural gas. Interest rate risk is caused by fluctuations in interest rates related to our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Fuel price risk, primarily in our cargo shipping segment, is a product of the fluctuation in fuel prices; however, this risk is partially reduced through fuel surcharges. With the exception of fuel price risk in our cargo shipping segment, we use derivative instruments to manage these risks. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

Our RMC is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions.

Weather and Natural Gas Price Risks

Distribution Operations Our utilities, excluding Atlanta Gas Light, are authorized to use natural gas cost recovery mechanisms that allow them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it has no natural gas price risk.

Nicor Gas and Elizabethtown Gas enter into derivative instruments to hedge the impact of market fluctuations in natural gas prices for customers. These derivatives are reflected at fair value and are not designated as hedges. Realized gains or losses on such instruments are included in the cost of gas delivered and are passed through directly to customers and therefore have no direct impact on earnings. Realized and unrealized changes in the fair value of these derivative instruments are deferred as regulatory assets or liabilities until recovered from or credited to our customers.

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 more information, see Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Natural gas price volatility” and the subheading “Hedges” and Note 2 to the consolidated financial statements under Item 8 herein.

Retail Operations and Wholesale Services We routinely utilize various types of derivative instruments to mitigate certain natural gas price and weather risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and OTC energy contracts, such as forward contracts, futures contracts, options contracts and swap agreements. Retail operations and wholesale services also actively manage storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. These hedging instruments are used to substantially lock in economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize our exposure to declining operating margins.

Midstream Operations We use derivative instruments to reduce our exposure to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas, conditioning gas and additional volumes of gas used to de-water our caverns (de-water gas) during the construction of storage facilities. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. Conditioning gas is used to ready a field for use and will be sold in connection with placing the storage facility into service. De-water gas is used to remove water from the cavern in anticipation of commercial service and will be sold after completion of de-watering. We also use derivative instruments for asset optimization purposes.

Consolidated The following tables include the fair values and average values of our consolidated derivative instruments as of the dates indicated. We base the average values on monthly averages for the 12 months ended December 31, 2013 and 2012.

	Derivative instruments average values (1) **at December 31,**	
In millions	**2013**	**2012**
Asset	$ 107	$ 208
Liability	49	101

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at December 31,	
In millions	**2013**	**2012**
Asset	$ 119	$ 144
Liability	80	39

The following table illustrates the change in the net fair value of our derivative instruments during the 12 months ended December 31, 2013, 2012 and 2011, and provides detail of the net fair value of contracts outstanding as of December 31, 2013, 2012 and 2011.

In millions	**2013**	**2012**	**2011**
Net fair value of derivative instruments outstanding at beginning of period	$ 36	$ 31	$ 55
Derivative instruments realized or otherwise settled during period	(62)	(61)	(74)
Net fair value of derivative instruments acquired during period	-	-	(5)
Change in net fair value of derivative instruments	(56)	66	55
Net fair value of derivative instruments outstanding at end of period	(82)	36	31
Netting of cash collateral	121	69	147
Cash collateral and net fair value of derivative instruments outstanding at end of period (1)	$ 39	$ 105	$ 178

(1) Net fair value of derivative instruments outstanding includes $3 million premium and associated intrinsic value at December 31, 2013, $4 million at December 31, 2012 and $3 million at December 31, 2011 associated with weather derivatives.

The sources of our net fair value at December 31, 2013 are as follows.

In millions	**Prices actively quoted (Level 1)** (1)	**Significant other observable inputs (Level 2)** (2)
Mature through 2014	$ (43)	$ (26)
Mature 2015 - 2016	(26)	15
Mature 2017 - 2018	(2)	-
Total derivative instruments (3)	$ (71)	$ (11)

(1) Valued using NYMEX futures prices.

(2) Valued using basis transactions that represent the cost to transport natural gas from a NYMEX delivery point to the contract delivery point. These transactions are based on quotes obtained either through electronic trading platforms or directly from brokers.

(3) Excludes cash collateral amounts.

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

We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period, SouthStar's portfolio of positions for the 12 months ended December 31, 2013, 2012 and 2011 were less than $0.1 million and Sequent had the following VaRs.

In millions	2013	2012	2011
Period end	$ 4.7	$ 1.8	$ 2.2
12-month average	2.3	2.0	1.6
High	4.9	4.8	3.1
Low	1.2	1.1	0.8

Fuel Price Risk

Cargo Shipping Tropical Shipping's objective is to reduce its exposure to higher fuel costs through fuel surcharges. However, these fuel surcharges do not remove our entire risk in periods of increasing fuel prices and volatility, or increased competition, and any relief may not be realized in the same period as the cost incurred. An increase of 10% in Tropical Shipping's average cost per gallon for vessel fuel results in approximately $6 million of additional annual fuel expense. Fuel surcharges would be implemented to reduce the impact of the increased fuel expense.

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $1.4 billion of variable-rate debt outstanding at December 31, 2013, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $14 million on an annualized basis.

We utilize interest rate swaps to help us achieve our desired mix of variable to fixed-rate debt. Our variable rate debt target generally ranges from 20% to 45% of total debt. We also may use forward-starting interest rate swaps and interest rate lock agreements to lock in fixed interest rates on our forecasted issuances of debt. The objective of these hedges is to offset the variability of future payments associated with the interest rate on debt instruments we expect to issue. The gain or loss on the interest rate swaps designated as cash flow hedges is generally deferred in accumulated OCI until settlement, at which point it is amortized to interest expense over the life of the related debt. For additional information, see Note 5 to our consolidated financial statements under Item 8 herein.

In April 2013, we entered into two ten-year, $50 million fixed-rate forward-starting interest rate swaps to hedge any potential interest rate volatility prior to our issuance of senior notes in the second quarter 2013. The average interest rate on these swaps was 1.98%. Including $200 million of ten-year, 1.78% fixed-rate forward-starting interest rate swaps that were executed in December 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 in May 2013, at which time we received $6 million in proceeds. The $6 million will be amortized to reduce interest expense over the first ten years of the 30-year senior notes.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk, as it bills 12 certificated and active Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2013, the four largest Marketers based on customer count accounted for approximately 16% of our consolidated operating margin and 21% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. The RMC reviews on a monthly basis the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer.

We believe that adequate policies and procedures have been put in place to properly quantify, manage and report on Atlanta Gas Light's credit risk exposure to Marketers.

Atlanta Gas Light also faces potential credit risk in connection with assignments of interstate pipeline transportation and storage capacity to Marketers. Although Atlanta Gas Light assigns this capacity to Marketers, in the event that a Marketer fails to pay the interstate pipelines for the capacity, the interstate pipelines would in all likelihood seek repayment from Atlanta Gas Light.

Our gas distribution businesses offer options to help customers manage their bills, such as energy assistance programs for low-income customers and a budget payment plan that spreads gas bills more evenly throughout the year. Customer credit risk has been substantially mitigated at Nicor Gas by the bad debt rider approved by the Illinois Commission on February 2, 2010, which 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 included in its rates for the respective year. For Virginia Natural Gas and Chattanooga Gas, we are allowed to recover the gas portion of bad debt write-offs through their gas recovery mechanisms.

Nicor Gas faces potential credit risk in connection with its natural gas sales and procurement activities to the extent a counterparty defaults on a contract to pay for or deliver at agreed-upon terms and conditions. To manage this risk, Nicor Gas maintains credit policies to determine and monitor the creditworthiness of its counterparties. In doing so, Nicor Gas seeks guarantees or collateral, in the form of cash or letters of credit, which limits its exposure to any individual counterparty and enters into netting arrangements to mitigate counterparty credit risk.

Certain of our derivative instruments contain credit-risk-related or other contingent features that could increase the payments for collateral we post in the normal course of business when our financial instruments are in net liability positions. As of December 31, 2013, for agreements with such features, our distribution operations derivative instruments with liability fair values totaled $2 million, for which we had posted no collateral to our counterparties.

Retail Operations We obtain credit scores for our firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed our credit threshold. We consider potential interruptible and large commercial customers based on reviews of publicly available financial statements and commercially available credit reports. Prior to entering into a physical transaction, we also assign physical wholesale counterparties an internal credit rating and credit limit based on the counterparties' Moody's, S&P and Fitch ratings, commercially available credit reports and audited financial statements.

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

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

We have a concentration of credit risk as measured by our 30-day receivable exposure plus forward exposure. As of December 31, 2013, excluding $8 million of customer deposits, our top 20 counterparties represented approximately 51% of the total counterparty exposure of $542 million.

As of December 31, 2013, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions.

	As of December 31,			
	Gross receivables		Gross payables	
In millions	2013	2012	2013	2012
Netting agreements in place:				
Counterparty is investment grade	$ 496	$ 485	$ 265	$ 282
Counterparty is non-investment grade	-	9	10	13
Counterparty has no external rating	260	175	393	315
No netting agreements in place:				
Counterparty is investment grade	29	7	2	1
Counterparty has no external rating	1	1	1	-
Amount recorded on Consolidated Statements of Financial Position	$ 786	$ 677	$ 671	$ 611

We have certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements with our counterparties would have totaled $9 million at December 31, 2013, which would not have a material impact to our consolidated results of operations, cash flows or financial condition.

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 accompanying 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the *Internal Control - Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 1992). 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 on Internal Control over Financial Reporting appearing under Item 9A. 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

PricewaterhouseCoopers LLP
Atlanta, GA
February 6, 2014

Management's Report on Internal Control Over Financial Reporting

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). Under the supervision and with the participation of our management, including 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 (COSO).

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.

Based on our evaluation under the framework in the *Internal Control - Integrated Framework* (1992) issued by COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2013, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

February 6, 2014

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

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

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

In millions	As of December 31, 2013	2012
Current assets		
Cash and cash equivalents	$ 105	$ 131
Short-term investments	50	58
Receivables		
Energy marketing	786	677
Gas	385	362
Unbilled revenues	268	235
Other	119	89
Less allowance for uncollectible accounts	29	28
Total receivables, net	1,529	1,335
Inventories		
Natural gas	637	679
Other	30	29
Total inventories	667	708
Regulatory assets	162	145
Derivative instruments	99	130
Prepaid expenses	65	141
Other	56	20
Total current assets	2,733	2,668
Long-term assets and other deferred debits		
Property, plant and equipment	11,104	10,478
Less accumulated depreciation	2,323	2,131
Property, plant and equipment, net	8,781	8,347
Goodwill	1,888	1,837
Regulatory assets	737	944
Intangible assets	173	96
Long-term investments	119	136
Pension assets	117	33
Derivative instruments	20	14
Other	88	66
Total long-term assets and other deferred debits	11,923	11,473
Total assets	$ 14,656	$ 14,141

See Notes to Consolidated Financial Statements.

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

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	432	334
Regulatory liabilities	183	161
Customer deposits and credit balances	136	143
Accrued taxes	85	53
Derivative instruments	75	33
Accrued wages and salaries	73	34
Accrued environmental remediation liabilities	70	57
Accrued interest	52	53
Accrued regulatory infrastructure program costs	5	121
Current portion of long-term debt and capital leases	-	226
Other	169	135
Total current liabilities	3,122	3,338
Long-term liabilities and other deferred credits		
Long-term debt	3,813	3,327
Accumulated deferred income taxes	1,667	1,588
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	75
Total long-term liabilities and other deferred credits	7,858	7,368
Total liabilities and other deferred credits	10,980	10,706
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	2,014
Retained earnings	1,126	1,035
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	3,631	3,413
Noncontrolling interest	45	22
Total equity	3,676	3,435
Total liabilities and equity	$ 14,656	$ 14,141

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

In millions, except per share amounts	Years ended December 31, 2013	2012	2011
Operating revenues (includes revenue taxes of $112 for 2013, $86 for 2012 and $9 for 2011)	$ 4,617	$ 3,922	$ 2,338
Operating expenses			
Cost of goods sold	2,332	1,791	1,097
Operation and maintenance	999	921	501
Depreciation and amortization	418	415	186
Nicor merger expenses	-	20	57
Taxes other than income taxes	193	165	57
Total operating expenses	3,942	3,312	1,898
Gain on sale of Compass Energy	11	-	-
Operating income	686	610	440
Other income, net	17	24	7
Interest expenses, net	(181)	(184)	(136)
Total other expense	(164)	(160)	(129)
Earnings before income taxes	522	450	311
Income tax expenses	191	164	125
Net income	331	286	186
Less net income attributable to the noncontrolling interest	18	15	14
Net income attributable to AGL Resources Inc.	$ 313	$ 271	$ 172
Per common share data			
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.65	$ 2.32	$ 2.14
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.64	$ 2.31	$ 2.12
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

In millions	Years Ended December 31, 2013	2012	2011
Net income	$ 331	$ 286	$ 186
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	413	285	119
Less comprehensive income attributable to noncontrolling interest	18	15	14
Comprehensive income attributable to AGL Resources Inc.	$ 395	$ 270	$ 105

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

In millions, except per share amounts	Common stock Shares	Common stock Amount	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
	AGL Resources Inc. Shareholders							
As of December 31, 2010	78.0	$ 391	$ 631	$ 943	$ (150)	$ (2)	$ 23	$1,836
Net income	-	-	-	172	-	-	14	186
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	$ 967	$ (217)	$ (7)	$ 21	$3,339
Net income	-	-	-	271	-	-	15	286
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	-	-	7	-	-	-	-	7
As of December 31, 2012	117.9	$ 590	$ 2,014	$ 1,035	$ (218)	$ (8)	$ 22	$3,435
Net income	-	-	-	313	-	-	18	331
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)
	-	-	(6)	-	-	-	-	(6)

Stock granted, share-based compensation, net of forfeitures								
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	-	-	12	-	-	-	-	12
As of December 31, 2013	118.9	$ 595	$ 2,054	$ 1,126	$ (136)	$ (8)	$ 45	$3,676

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Years ended December 31, 2013	2012	2011
Cash flows from operating activities			
Net income	$ 331	$ 286	$ 186
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	418	415	186
Change in derivative instrument assets and liabilities	66	72	(17)
Deferred income taxes	(7)	154	214
Gain on sale of Compass Energy	(11)	-	-
Changes in certain assets and liabilities			
Trade payables, other than energy marketing	92	51	(68)
Prepaid taxes	70	37	(88)
Accrued expenses	70	(22)	(77)
Inventories	41	42	158
Accrued natural gas costs	2	37	(3)
Receivables, other than energy marketing	(80)	19	45
Energy marketing receivables and trade payables, net	(49)	(49)	27
Other, net	28	(39)	(112)
Net cash flow provided by operating activities	971	1,003	451
Cash flows from investing activities			
Acquisition of Nicor, net of cash acquired	-	-	(912)
Expenditures for property, plant and equipment	(749)	(782)	(427)
Acquisitions of assets	(154)	-	-
Disposition of assets	19	-	-
Other, net	8	(4)	-
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	(26)	62	45
Cash and cash equivalents at beginning of period	131	69	24
Cash and cash equivalents at end of period	$ 105	$ 131	$ 69
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.

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.

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

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, we had $80 million of cash and short and long-term investments in our Consolidated Statements of Financial Position held by Tropical Shipping. These cash and investment amounts are available for use by us or our other operations only if we repatriate a portion of Tropical Shipping’s earnings in the form of a dividend, and pay a significant amount of U.S. income tax that has been previously deferred. See Note 12 for additional information on our income taxes.

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	$ 8,384	$ 7,992
Storage facilities	1,170	1,149
Shipping vessels and containers	148	145
Other	854	820
Construction work in progress	548	372
Total PP&E, gross	11,104	10,478
Less accumulated depreciation	2,323	2,131
Total PP&E, net	$ 8,781	$ 8,347

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, Cargo Shipping 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
Shipping vessels	20 - 25
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)	$ 19	$ 9	$ 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	Cargo Shipping	Other	Consolidated
Goodwill - December 31, 2011	$ 1,586	$ 124	$ 2	$ 16	$ 77	$ 8	$ 1,813
Adjustments to initial Nicor purchase price allocation and other	54	(2)	(2)	(2)	(16)	(8)	24
Goodwill - December 31, 2012	1,640	122	-	14	61	-	1,837
2013 acquisitions	-	51	-	-	-	-	51
Goodwill - December 31, 2013	$ 1,640	$ 173	$ -	$ 14	$ 61	$ -	$ 1,888

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.

In millions	Weighted average amortization period (in years)	December 31, 2013 Gross	December 31, 2013 Accumulated amortization	December 31, 2013 Net	December 31, 2012 Gross	December 31, 2012 Accumulated amortization	December 31, 2012 Net
Customer relationships							
Retail operations	13	$ 130	$ (15)	$ 115	$ 53	$ (6)	$ 47
Cargo shipping	18	6	-	6	6	-	6
Trade names							
Retail operations	13	45	(6)	39	30	(2)	28
Cargo shipping	15	15	(2)	13	15	(1)	14
Wholesale services	-	-	-	-	1	-	1
Total		$ 196	$ (23)	$ 173	$ 105	$ (9)	$ 96

Amortization expense was $14 million in 2013, $9 million in 2012 and $0 in 2011. Amortization expense for the next five years is estimated to be as follows:

In millions	
2014	$ 16
2015	16
2016	16
2017	15
2018	15

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.

Cargo shipping Revenues are recognized 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.

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.

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 owned by our cargo shipping business.

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	$ 13	$ 6	$ 4
Equity investment income	3	13	1
Other, net	1	5	2
Total other income	$ 17	$ 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	2012	2011
Net income attributable to AGL Resources Inc.	$ 313	$ 271	$ 172
Denominator:			
Basic weighted average number of shares outstanding (1)	117.9	117.0	80.4
Effect of dilutive securities	0.4	0.5	0.5
Diluted weighted average number of shares outstanding (2)	118.3	117.5	80.9
Earnings per share			
Basic	$ 2.65	$ 2.32	$ 2.14
Diluted (2)	$ 2.64	$ 2.31	$ 2.12

(1) Daily weighted average shares outstanding.
(2) 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 expected to be amortized on a straight-line basis over an estimated period of 14 to 16 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.

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**	**2012**
Regulatory assets		
Recoverable regulatory infrastructure program costs	$ 48	$ 47
Recoverable ERC	45	38
Recoverable pension and retiree welfare benefit costs	9	19
Other	60	41
Total regulatory assets - current	162	145
Recoverable ERC	433	438
Recoverable pension and retiree welfare benefit costs	99	196
Recoverable regulatory infrastructure program costs	87	167
Long-term debt fair value adjustment	82	90
Other	36	53
Total regulatory assets - long-term	737	944
Total regulatory assets	$ 899	$ 1,089
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

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.

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.

In millions	Bad debt experience	Total refund	Amount refunded in 2012	Amount refunded in 2013	Amount to be refunded in 2014	Amount to be refunded in 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 By order of the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Georgia Commission), Atlanta Gas Light began a pipeline replacement program to replace all bare steel and cast iron pipe in its system by December 2013.

The order provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of straight-fixed-variable rates and a pipeline replacement revenue rider. The regulatory asset has two components: (i) the revenues recognized to date that have not yet been recovered from customers through the rate riders, and (ii) the future expected costs to be recovered through the base rates.

Atlanta Gas Light has recorded a current regulatory asset of $48 million, which represents the amount of recognized revenues expected to be collected from customers over the next 12 months. Atlanta Gas Light has also recorded a non-current asset of $87 million, which represents the expected future collection of revenues already recognized. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $49 million in 2013
- $51 million in 2012
- $48 million in 2011

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the pipeline replacement program 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. In the near term, the primary financial impact to Atlanta Gas Light from the pipeline replacement program is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

Our STRIDE program is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), the pipeline replacement program that ended in 2013, and a new component, the Integrated Vintage Plastic Replacement Program (i-VPR). The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. Our i-CGP authorizes Atlanta Gas Light to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia. All related costs will be recovered through a surcharge. 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.

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%. 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.

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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.

Money Market Funds

At December 31, 2013 and 2012, the fair values of our money market funds, which were recorded within short-term investments, 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.

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.

In millions	As of December 31, 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

	Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	no impact on earnings. Any hedge ineffectiveness will impact earnings
Not designated as hedges	Derivative carried at fair value	Realized and unrealized gains or losses on the derivative instrument are recognized in earnings
	Distribution operations' gains and losses on derivative instruments are deferred as regulatory assets or liabilities until included in cost of goods sold	Gains or losses on these derivative instruments are ultimately included in billings to customers and are recognized in cost of goods sold in the same period as the related revenues

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:

	December 31,	
In Bcf (1)	**2013** (2)	**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:

		December 31, 2013		December 31, 2012	
In millions	**Classification**	**Assets**	**Liabilities**	**Assets**	**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.

Glossary

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

Dollars in millions	Pension plans 2013	Pension plans 2012	Pension plans 2011	Welfare plans 2013	Welfare plans 2012	Welfare plans 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.

Dollars in millions	Pension plans 2013	Pension plans 2012	Welfare plans 2013	Welfare plans 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.

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

Glossary

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 $16 million in 2013, $14 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	103,343	108,132	65,843
Average per-share purchase price	$ 42.96	$ 38.96	$ 40.55
Total purchase price discount	$ 664,286	$ 618,278	$ 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		**Nicor Gas**	
	December 31,		**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. The primary risks associated with SouthStar are discussed in our risk factors included in Item 1A.

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**	**SouthStar** (1)	**%**(2)	**Consolidated**	**SouthStar** (1)	**%**(2)
Current assets	$ 2,733	$ 264	10%	$ 2,668	$ 201	8%
Goodwill and other intangible assets	2,061	139	7	1,933	-	-
Long-term assets and other deferred debit	9,862	12	-	9,540	10	-
Total assets	$ 14,656	$ 415	3%	$ 14,141	$ 211	1%
Current liabilities	$ 3,122	$ 95	3%	$ 3,338	$ 62	2%
Long-term liabilities and other deferred credits	7,858	-	-	7,368	-	-
Total liabilities	10,980	95	1	10,706	62	1
Equity	3,676	320	9	3,435	149	4
Total liabilities and equity	$ 14,656	$ 415	3%	$ 14,141	$ 211	1%

(1) 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.
(2) 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	5	2
Taxes other than income taxes	1	2
Total operating expenses	569	478
Operating income	$ 118	$ 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)	233	39	34	28	25	18	89
Asset management agreements (7)	19	8	5	4	2	-	-
Standby letters of credit, performance/surety bonds (8)	29	29	-	-	-	-	-
Other	15	6	3	3	2	1	-
Total	$ 5,493	$ 1,000	$ 724	$ 495	$ 314	$ 266	$ 2,694

(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	2012	2011
Current income taxes			
Federal	$ 166	$ 9	$ (89)
State	35	4	1
Deferred income taxes			
Federal	2	134	196
State	(9)	20	18
Amortization of investment tax credits	(3)	(3)	(1)
Total	$ 191	$ 164	$ 125

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	2012	2011
Computed tax expense at statutory rate	$ 178	$ 158	$ 109
State income tax, net of federal income tax benefit	21	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	$ 191	$ 164	$ 125

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	2012
Accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$ 1,613	$ 1,533
Undistributed earnings of foreign subsidiaries	26	30
Investments in partnerships	18	26
Acquisition intangibles	15	26
Mark-to-market	-	22
Other	128	126
Total accumulated deferred income tax liabilities	1,800	1,763
Accumulated deferred income tax assets		
Unfunded pension and retiree welfare benefit obligation	92	145
Deferred investment tax credits	7	9
Mark-to-market	4	-
Other	44	43
Total accumulated deferred income tax assets	147	197
Valuation allowances (1)	(14)	(22)
Total accumulated deferred income tax assets, net of valuation allowance	133	175
Net non-current accumulated deferred tax liability	$ 1,667	$ 1,588

(1) 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.

To the extent foreign cargo shipping earnings are not repatriated to the U.S., such earnings are not currently subject to taxation. In addition, to the extent such earnings are indefinitely reinvested offshore, no deferred income tax expense is recorded by us. At December 31, 2013, we had $26 million of deferred income tax liabilities related to $75 million of cumulative undistributed earnings of our foreign subsidiaries. At December 31, 2012, we had $30 million of deferred income tax liabilities related to $87 million of cumulative undistributed earnings of our foreign subsidiaries. See Note 2 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 five operating segments - distribution operations, retail operations, wholesale services, midstream operations, cargo shipping 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.

Our cargo shipping segment transports containerized cargo between Florida, the eastern coast of Canada, the Bahamas and the Caribbean region. Our cargo shipping segment also includes amounts related to cargo insurance coverage sold to our customers and other third parties. Our cargo shipping segment's vessels are under foreign registry, and its containers are considered instruments of international trade. Although the majority of its long-lived assets are foreign owned and its revenues are derived from foreign operations, the functional currency is generally the U.S. dollar. Our other segment includes intercompany eliminations and aggregated subsidiaries that are not significant on a stand-alone basis and that do not fit into one of our other five 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	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 3,275	$ 858	$ 45	$ 74	$ 365	$ -	$ 4,617
Intercompany revenues (1)	182	-	13	-	-	(195)	-
Total operating revenues	3,457	858	58	74	365	(195)	4,617
Operating expenses							
Cost of goods sold	1,687	564	21	33	222	(195)	2,332
Operation and maintenance	690	132	48	24	115	(10)	999
Depreciation and amortization	346	22	1	17	19	13	418
Taxes other than income taxes	167	3	3	5	6	9	193
Total operating expenses	2,890	721	73	79	362	(183)	3,942
Gain on sale of Compass Energy	-	-	11	-	-	-	11
Operating income (loss)	567	137	(4)	(5)	3	(12)	686
Other income (expense)	15	-	-	(5)	9	(2)	17
EBIT	$ 582	$ 137	$ (4)	$ (10)	$ 12	$ (14)	$ 703
Identifiable and total assets (3)	$ 11,727	$ 694	$ 1,166	$ 713	$ 445	$ (89)	$ 14,656
Capital expenditures	$ 684	$ 9	$ 2	$ 12	$ 18	$ 24	$ 749

2012

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 2,710	$ 733	$ 58	$ 78	$ 342	$ 1	$ 3,922
Intercompany revenues (1)	167	2	30	-	-	(199)	-
	2,877	735	88	78	342	(198)	3,922

Total operating revenues							
Operating expenses							
Cost of goods sold	1,221	488	38	32	208	(196)	1,791
Operation and maintenance	642	114	48	19	109	(11)	921
Depreciation and amortization	351	13	2	14	22	13	415
Nicor merger expenses (2)	-	-	-	-	-	20	20
Taxes other than income taxes	140	4	4	5	6	6	165
Total operating expenses	2,354	619	92	70	345	(168)	3,312
Operating income (loss)	523	116	(4)	8	(3)	(30)	610
Other income	9	-	1	2	11	1	24
EBIT	$ 532	$ 116	$ (3)	$ 10	$ 8	$ (29)	$ 634
Identifiable and total assets (3)	$ 11,320	$ 511	$ 1,218	$ 720	$ 464	$ (92)	$ 14,141
Capital expenditures	$ 649	$ 8	$ 3	$ 62	$ 7	$ 53	$ 782

Glossary

2011

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Cargo shipping	Other and intercompany eliminations (4)	Consolidated
Operating revenues from external parties	$ 1,451	$ 702	$ 95	$ 70	$ 19	$ 1	$ 2,338
Intercompany revenues (1)	146	-	3	-	-	(149)	-
Total operating revenues	1,597	702	98	70	19	(148)	2,338
Operating expenses							
Cost of goods sold	625	534	41	33	12	(148)	1,097
Operation and maintenance	362	71	48	15	7	(2)	501
Depreciation and amortization	160	2	1	10	1	12	186
Nicor merger expenses (2)	-	-	-	-	-	57	57
Taxes other than income taxes	44	2	3	3	-	5	57
Total operating expenses	1,191	609	93	61	20	(76)	1,898
Operating income (loss)	406	93	5	9	(1)	(72)	440
Other income	6	-	-	-	1	-	7
EBIT	$ 412	$ 93	$ 5	$ 9	$ -	$ (72)	$ 447
Capital expenditures	$ 365	$ 2	$ 1	$ 35	$ -	$ 24	$ 427

(1) 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.
(2) Transaction expenses associated with the Nicor merger are shown separately to better compare year-over-year results.
(3) Identifiable assets are those dedicated to each segment's operations.
(4) Our other segment's assets consist primarily of cash and cash equivalents, PP&E and the effect of intercompany eliminations.

Note 14 - 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. Our quarterly financial data for 2013, 2012 and 2011 are summarized below.

In millions, except per share amounts	March 31	June 30	September 30	December 31
2013				
Operating revenues	$ 1,709	$ 904	$ 675	$ 1,329
Operating income	299	122	82	183
EBIT	304	129	89	181
Net income	164	50	28	89
Net income attributable to AGL Resources Inc.	154	49	28	82
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.31	0.41	0.24	0.69
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	1.31	0.41	0.24	0.68
2012				
Operating revenues	$ 1,404	$ 686	$ 614	$ 1,218
Operating income	262	91	54	203
EBIT	266	100	60	208
Net income	139	35	9	103
Net income attributable to AGL Resources Inc.	130	34	9	98
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.12	0.28	0.08	0.84
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	1.11	0.28	0.08	0.84
2011				
Operating revenues	$ 878	$ 375	$ 295	$ 790
Operating income	238	60	24	118
EBIT	239	62	25	121
Net income (loss)	134	19	(4)	37
Net income (loss) attributable to AGL Resources Inc.	124	18	(3)	33
Basic earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	1.60	0.23	(0.04)	0.37
Diluted earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	1.59	0.23	(0.04)	0.37

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 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). 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. Our disclosure controls and procedures however are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2013, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

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.

Reports of Management and Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

Management has assessed, and our independent registered public accounting firm, PricewaterhouseCoopers LLP, has audited, our internal control over financial reporting as of December 31, 2013. The unqualified reports of management and PricewaterhouseCoopers LLP thereon are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

ITEM 9B. OTHER INFORMATION

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

EXECUTIVE OFFICERS OF THE REGISTRANT

Set forth below are the names, ages and positions of our executive officers along with their business experience during the past five years. All officers serve at the discretion of our Board of Directors. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 58	
Chairman, President and Chief Executive Officer	October 2007 - Present
Andrew W. Evans, Age 47	
Executive Vice President and Chief Financial Officer	November 2010 - Present
Executive Vice President, Chief Financial Officer and Treasurer	June 2009 - November 2010
Executive Vice President and Chief Financial Officer	May 2006 - June 2009
Henry P. Linginfelter, Age 53	
Executive Vice President, Distribution Operations	December 2011 - Present
Executive Vice President, Utility Operations	June 2007 - December 2011
Melanie M. Platt, Age 59	
Executive Vice President, Chief People Officer	December 2011 - Present
Senior Vice President, Human Resources and Marketing Communications	November 2008 - December 2011
Paul R. Shlanta, Age 56	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 - Present
Peter I. Tumminello, Age 51	
Executive Vice President, Wholesale Services, and President Sequent	December 2011 - Present
President, Sequent	April 2010 - December 2011

Executive Vice President, Business Development and Support, Sequent	February 2007 - April 2010

The other information required by this item with respect to directors will be set forth under the captions “Proposal 1 -Election of Directors,” “Corporate Governance - Ethics and Compliance Program,” “Committees of the Board” and “Audit Committee” in the Proxy Statement for our 2014 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item will be set forth under the captions “Compensation and Management Development Committee Report,” “Compensation and Management Development Committee Interlocks and Insider Participation,” “Director Compensation,” “Compensation Discussion and Analysis” and “Executive Compensation” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference, except for the information under the caption “Compensation and Management Development Committee Report” which is specifically not so incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item will be set forth under the captions “Security Ownership of Certain Beneficial Owners and Management” and “Executive Compensation - Equity Compensation Plan Information” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information required by this item will be set forth under the captions “Corporate Governance - Director Independence” and “- Policy on Related Person Transactions” and “Certain Relationships and Related Transactions” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this item will be set forth under the caption “Proposal 2 - Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2014” in the Proxy Statement or subsequent amendment referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

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 (Loss) 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.

(3) 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.
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

Glossary

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	Filed herewith
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 (Officer Incentive Plan)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.2
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	Filed herewith
10.1.ab +	Second Amendment to the Nonqualified Savings Plan	AGL Resources	Filed herewith
10.1.ac +	Third Amendment to the Nonqualified Savings Plan	AGL Resources	Filed herewith
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.
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

Glossary

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.
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	Filed herewith
23	Consent of PricewaterhouseCoopers LLP	AGL Resources	Filed herewith
24	Powers of Attorney	AGL Resources	Included on signature page hereto
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 February 6, 2014.

AGL RESOURCES INC.

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

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2013, and to file the same, with all exhibits thereto and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite or necessary to be done, as fully to all intents and purposes as he or she might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated as of February 6, 2014.

Signatures	Title
/s/ John W. Somerhalder II John W. Somerhalder II	Chairman, President and Chief Executive Officer (Principal Executive Officer)
/s/ Andrew W. Evans Andrew W. Evans	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ Bryan E. Seas Bryan E. Seas	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)
/s/ Sandra N. Bane Sandra N. Bane	Director
/s/ Thomas D. Bell, Jr. Thomas D. Bell, Jr.	Director
/s/ Norman R. Bobins Norman R. Bobins	Director
/s/ Charles R. Crisp Charles R. Crisp	Director
/s/ Brenda J. Gaines Brenda J. Gaines	Director
/s/ Arthur E. Johnson Arthur E. Johnson	Director
/s/ Wyck A. Knox, Jr. Wyck A. Knox, Jr.	Director

/s/ Dennis M. Love Dennis M. Love	Director
/s/ Charles H. McTier Charles H. McTier	Director
/s/ Dean R. O'Hare Dean R. O'Hare	Director
/s/ Armando J. Olivera Armando J. Olivera	Director
/s/ John E. Rau John E. Rau	Director
/s/ James A. Rubright James A. Rubright	Director
/s/ Bettina M. Whyte Bettina M. Whyte	Director
/s/ Henry C. Wolf Henry C. Wolf	Director

Schedule II

AGL Resources Inc. and Subsidiaries

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

		Additions			
In millions	Balance at beginning of period	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

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PERFORMANCE SHARE UNIT AWARD NO. PSU13-

AGL RESOURCES INC.
AMENDED AND RESTATED OMNIBUS PERFORMANCE INCENTIVE PLAN
PERFORMANCE SHARE UNIT (PSU) AWARD AGREEMENT

This Agreement between AGL Resources Inc. (the "Company") and the Recipient sets forth the terms of the Performance Share Unit Award (the "Award") granted under the above-named Plan. Capitalized terms used herein and not otherwise defined shall have the meaning assigned to such terms in the Plan.

Name of Recipient:

Date of Award: **Performance Award:**

Performance Measurement Period:

Performance Measurement: The performance measure for this Award relates to the Company's Relative Total Shareholder Return (RTSR). For the purposes of this Award, performance is specifically measured relative to a group of peer companies, known as the Proxy Peers, which are identified in Table One below. The Company's ranked Total Shareholder Return (TSR) relative to the Proxy Peers (RTSR) determines the level of Performance Award that will be paid at the end of the Performance Measurement Period. TSR is calculated as follows:

Price_{begin} = share price at the beginning of the period
Price_{end} = share price at the end of the period
$\text{Dividends}_{paid\ plus\ reinvested}$ = total dividends for the period

$$\text{TSR} = (\text{Price}_{end} - \text{Price}_{begin} + \text{Dividends}_{paid\ plus\ reinvested}) / \text{Price}_{begin}$$

Performance Calculation: At the end of the Performance Measurement Period, the Award will vest and the units will be adjusted based upon the Company's TSR ranking, relative to the Proxy Peer Group (RTSR) as shown in Table Two and the example below. If a peer company is dropped from the Proxy Peers during the Performance Measurement Period, the ranking will be relative to the remaining companies, and the associated award payment levels will be adjusted accordingly.

Table One
Proxy Peers

Table Two
RTSR Rank and Associated Award Payment Levels

Company RTSR Rank	Percentile Rank	Award Payment Level
1	100%	200%
2	92%	184%
3	83%	166%
4	75%	150%
5	67%	134%
6	58%	116%

7	50%	100%
8	42%	84%
9	33%	66%
10	25%	50%
>10	0%	0%

Vesting: Unless the Award is forfeited prior to the Vesting Date (as defined below), in accordance with this Agreement, the Award shall vest on the date that the Compensation and Management Development Committee (the "Compensation Committee") certifies the level of performance with respect to the Company's TSR and RTSR ranking at the end of the Performance Measurement Period (the "Vesting Date").

Payment: This Award shall be payable 50% in shares of AGL common stock, and 50% in cash within thirty (30) days following the Vesting Date, pursuant to the terms of the Plan, but in no event later than March 15 of the year in which the Vesting Date occurred. The number of shares of AGL common stock will be equal to the number of units to be settled in stock. The cash portion will be calculated by multiplying the number of units to be settled in cash by AGL's share price as of the close the day prior to the Vesting Date. Required tax withholding for the entire Award will be deducted from the cash portion of the Award. While the intention is to pay Award proceeds 50% in shares of AGL common stock and 50% in cash, the Compensation Committee reserves the right to revise the stock and cash proportions, if it deems such revision is necessary or advisable, in its good faith sole discretion.

Example Calculation of Award and Payment
Performance Award: 1,500 units
Closing Price at Vesting Date - $38.49
Company RTSR Rank - 5th (67th percentile, per table 2)

Award Payment Level - 134%, per table 2
Adjusted Performance Share Units – 1,500 units x 134% = 2,010 units
Units Settled in Stock = 50% x 2,010 units = 1,005 units awarded
Units Settled in Cash = 50% x 2,010 units x $38.49 = $38,682.45 awarded, required to first pay required tax withholding, balance paid in cash.

Forfeiture of Award; Termination of employment: If the Award does not vest for any reason, then the Award shall be forfeited immediately.

In addition, if your employment is terminated for any reason other than as set forth below or by reason of death, Disability, or Retirement, prior to the Vesting Date, then this Award shall be forfeited as of the date of your termination of employment. If you terminate employment by reason of death or Disability or Retirement, then performance shares shall vest and become non-forfeitable on a prorate basis, determined with respect to the number of months that have elapsed during the vesting period, prior to the date of such termination of employment, provided that such pro rata accelerated vesting shall be conditioned upon the satisfaction of applicable performance-based vesting conditioning, as measured [and payable, if at all following] the end of the performance period.

Personnel Non-Solicitation. In consideration of the benefits and promises set forth in this Agreement, Recipient agrees that, for a period of 24 months after termination of Recipient's employment for any reason (whether voluntary or involuntary), Recipient will not, directly or indirectly, solicit, divert, or hire, or attempt to solicit, divert, or hire, any person who is at the time, or was within the 24 months preceding the solicitation or other action, employed or retained by the Company.

Change in Control: Notwithstanding the vesting provision above, in the event of a Change in Control of the Company, this Award shall become vested, as set forth below, pursuant to Section 12.2 of the Plan if: (a) upon the date that it is not assumed or substituted by the Surviving Entity; or (b) if it is assumed or substituted by the Surviving Entity, upon the date within a two-year period following the Change in Control, that your employment is terminated without Cause or that you resign for Good Reason (each, a "Change in Control Related Vesting Date"). Such vesting will be prorated on a daily basis based upon the length of time within the Performance Measurement Period that has elapsed prior to the date of the Change in Control or termination of employment (as applicable) and will be based upon an assumed achievement of all relevant performance goals at: (i) the target level if the Change in Control or termination of employment (as applicable) occurs during the first half of the Performance Measurement Period; and (ii) the actual level of achievement as of the date of the Change in Control or termination of employment (as applicable) of all relevant performance goals if the Change in Control or termination of employment (as applicable) occurs during the second half of the Performance Measurement Period. This Award shall be payable in cash to the Recipient within thirty (30) days following the Change in Control Related Vesting Date, but in no event later than March 15 of the year following the year in which the Change in Control Related Vesting Date occurred.

This Agreement is subject to the terms and conditions of the Plan. You have received a copy of the Plan's prospectus that includes a copy of the Plan. By signing this Agreement, you agree to the terms of the Plan and this Agreement, which may be amended only upon a written agreement signed by the Company and you.

This __ day of , 201_

AGL RESOURCES INC. **RECIPIENT:**

/s/ Melanie M. Platt ______________________________
Melanie M. Platt
Executive Vice President

FIRST AMENDMENT TO THE

AGL RESOURCES INC. NONQUALIFIED SAVINGS PLAN
(as amended and restated effective January 1, 2009)

THIS AMENDMENT to the AGL Resources Inc. Nonqualified Savings Plan (the "Plan") is made on this 18th day of December, 2009, by the Administrative Committee of the Plan (the "Committee").

W I T N E S S E T H :

WHEREAS, AGL Resources Inc. maintains the Plan, which was most recently amended and restated effective as of January 1, 2009, for the benefit of a select group of management and highly compensated employees; and

WHEREAS, Section 10.1 of the Plan provides that the Committee has the authority to amend the Plan at any time, subject to certain restrictions that do not apply; and

WHEREAS, the Committee desires to amend the Plan to (i) clarify the formula for calculating matching contributions; and (ii) provide that participant deferral elections will apply only to the year for which they are made, rather than remaining in effect from year-to-year until modified for a subsequent year;

NOW, THEREFORE, the Plan is hereby amended as follows, effective as of December 18, 2009:

1. Section 3.1(b)(2) is amended to read as follows:

(2) Terms, Modification and Revocation. A Participant may change his Deferral Election and/or Bonus Deferral Election for the Plan Year any time prior to the deadline specified in subsection (b)(1)(A) above, subject to any restrictions or procedures determined by the Administrative Committee, but may not make any changes to his Deferral Election after making an election under subsection (b)(1)(B) above. In the event that the Administrative Committee permits a Bonus Deferral Election to be made under subsection (b)(1)(C) above, the Participant may change his Bonus Deferral Election any time prior to the deadline specified in subsection (b)(1)(C), but not after any earlier deadline established by the Administrative Committee. Upon the applicable deadline, each Participant's Deferral Election and/or Bonus Deferral Election, or failure to elect, shall become irrevocable for the Plan Year except as provided under this subsection (2). A Participating Company may terminate an Active Participant's Deferral Election and/or Bonus Deferral Election as permitted under Code §409A, including (i) upon his receipt of a hardship withdrawal as provided in Section 7.5 of the Plan, and (ii) no later than the end of the calendar year or the 15th day of the third calendar month, whichever is later, following the date the Active Participant incurs a disability (defined for this purpose as a medically determinable physical or mental impairment resulting in the Active Participant's inability to perform the duties of his or her position or any substantially similar position, which can be expected to result in death or to last for a continuous period of at least 6 months). An Active Participant shall not have a direct or indirect election as to whether the Participating Company's discretion under the preceding sentence will be exercised. Each Active Participant's Deferral Election and Bonus Deferral Election shall remain in effect only for the year for which it is made. An Active Participant may make a new Deferral Election and/or Bonus Deferral Election prior to the beginning of a Plan Year for Before-Tax Contributions attributable to services performed during that Plan Year. Upon an Active Participant's Separation from Service, his Deferral Election shall remain in effect through the end of the then-current Plan Year, and his Bonus Deferral Election shall apply to the Bonus(es) (if any) earned for the then-current Plan Year.

2. Section 3.2 is amended to read as follows:

3.2 Matching Contributions.

(a) CAE Participants. For each Active Participant (other than those described in subsection (b) hereof) on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to the difference between:

(1) 65% of the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan, plus the maximum amount of elective deferrals permitted under the RSP (without taking into account catch-up contributions) for the Plan Year pursuant to Code §402(g), and (B) 8% of the Participant's Compensation; minus

(2) the maximum matching contribution an Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(b) FAE Participants. For each Active Participant who is eligible to accrue benefits under Section 4.6(a)(1) of the AGL Resources Inc. Retirement Plan, on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to the difference between:

(1) 65% of the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan, plus the maximum amount of elective deferrals permitted under the RSP (without taking into account catch-up contributions) for the Plan Year pursuant to Code §402(g), and (B) 6% of the Participant's Compensation; minus

(2) the maximum matching contribution an Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(c) Timing. Matching Contributions shall be made to the Plan once each year within the period of two months following the last day of each Plan Year.

IN WITNESS WHEREOF, the Committee has caused its duly authorized member to execute this First Amendment on the date first written above.

ADMINISTRATIVE COMMITTEE

By: /s/ Martin Friedgood

Name: Martin Friedgood

Date: December 18, 2009

SECOND AMENDMENT TO THE
AGL RESOURCES INC. NONQUALIFIED SAVINGS PLAN
(as amended and restated effective January 1, 2009)

THIS AMENDMENT to the AGL Resources Inc. Nonqualified Savings Plan (the “Plan”) is made by the Administrative Committee of the Plan (the “Committee”).

W I T N E S S E T H :

WHEREAS, AGL Resources Inc. maintains the Plan, which was most recently amended and restated effective as of January 1, 2009, for the benefit of a select group of management and highly compensated employees; and

WHEREAS, Section 10.1 of the Plan provides that the Committee has the authority to amend the Plan at any time, subject to certain restrictions that do not apply; and

WHEREAS, the Committee desires to amend the Plan to provide for a new matching formula to coordinate with the new matching formula under the Company’s 401(k) plans, for participants who do not accrue additional benefits under the Company’s defined benefit pension plan;

NOW, THEREFORE, the Plan is hereby amended as follows, effective as of January 1, 2013:

1. Section 1.41 is amended to read as follows:

1.41 <u>**Retirement Savings Plus Plan**</u> or <u>**RSP**</u> shall mean the AGL Resources Inc. Retirement Savings Plus Plan and/or (except as used in Article V) another 401(k) plan maintained by the Affiliates, as the same may be amended from time to time.

2. Section 3.2 is amended to read as follows:

3.2 <u>**Matching Contributions**</u>.

(a) <u>**DB Eligible Participants**</u>. For each Active Participant, other than those described in subsection (b) hereof, on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to the difference between:

(1) 65% of the lesser of (A) the sum of the Participant’s Before-Tax Contributions under this Plan attributable to the Plan Year, plus the maximum amount of elective deferrals subject to matching under the RSP (without taking into account catch-up contributions) for the Plan Year pursuant to Code §§402(g) and 401(a)(17), and (B) 8% of the Participant’s Compensation earned during the Plan Year; <u>minus</u>

(2) the maximum matching contribution the Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(b) **DB Ineligible Participants**. For each Active Participant who is not eligible to accrue benefits under the AGL Resources Inc. Retirement Plan (but excluding all attachments to such plan that provide for benefits historically provided under the Nicor Companies Pension and Retirement Plan), on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to:

(1) the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan attributable to the Plan Year, plus the maximum amount of elective deferrals subject to matching under the RSP (without taking into account catch-up contributions) for the Plan Year pursuant to Code §§402(g) and 401(a)(17), and (B) 3% of the Participant's Compensation earned during the Plan Year; plus

(2) 75% of the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan attributable to the Plan Year, plus the maximum amount of elective deferrals subject to matching under the RSP (without taking into account catch-up contributions) for the Plan Year pursuant to Code §§402(g) and 401(a)(17), minus 3% of the Participant's Compensation earned during the Plan Year, but not less than zero; and (B) 3% of the Participant's Compensation earned during the Plan Year; minus

(3) the maximum matching contribution the Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(c) **Timing.** Matching Contributions shall be made to the Plan once each year within the period of two months following the last day of the Plan Year to which the Matching Contributions relate.

3. Except as provided herein, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Committee has caused its duly authorized member to execute this Amendment on the date written below.

ADMINISTRATIVE COMMITTEE

By: /s/ Martin Friedgood

Name: Martin Friedgood

Date: December 19, 2012

THIRD AMENDMENT TO THE
AGL RESOURCES INC. NONQUALIFIED SAVINGS PLAN
(as amended and restated effective January 1, 2009)

THIS AMENDMENT to the AGL Resources Inc. Nonqualified Savings Plan (the "Plan") is made by the Administrative Committee of the Plan (the "Committee").

W I T N E S S E T H :

WHEREAS, AGL Resources Inc. maintains the Plan, which was most recently amended and restated effective as of January 1, 2009, for the benefit of a select group of management and highly compensated employees; and

WHEREAS, Section 10.1 of the Plan provides that the Committee has the authority to amend the Plan at any time, subject to certain restrictions that do not apply; and

WHEREAS, the Committee desires to amend the Plan to modify the matching formula to coordinate with recent changes to the matching formula under the Company's 401(k) plans;

NOW, THEREFORE, the Plan is hereby amended as follows, effective as of January 1, 2013:

1. Section 3.2 is amended to read as follows:

3.2 **Matching Contributions**.

(a) **DB Eligible AGL Participants**. For each Active Participant, other than those described in subsections (b) and (c) hereof, on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to the difference between:

(1) 65% of the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan during the Plan Year (calculated by taking into account Before-Tax Contributions on Bonuses that became payable during the Plan Year, regardless of when such Bonuses were earned), plus the maximum amount of elective deferrals subject to matching under the RSP for the Plan Year (taking into account Code §§402(g), 414(v) and 401(a)(17), as applicable), and (B) 8% of the Participant's Compensation payable during the Plan Year (taking into account Bonuses that became payable during the Plan Year, regardless of when such Bonuses were earned); minus

(2) the maximum matching contribution the Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(b) **DB Ineligible AGL Participants**. For each Active Participant who is not eligible to accrue benefits under the AGL Resources Inc. Retirement Plan and is not a Nicor Participant (as defined in the RSP), on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to:

(1) the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan during the Plan Year (calculated by taking into account Before-Tax Contributions on Bonuses that became payable during the Plan Year, regardless of when such Bonuses were earned), plus the maximum amount of elective deferrals subject to matching under the RSP for the Plan Year (taking into account Code §§402(g), 414(v) and 401(a)(17), as applicable), and (B) 3% of the Participant's Compensation payable during the Plan Year (taking into account Bonuses that became payable during the Plan Year, regardless of when such Bonuses were earned); plus

(2) 75% of the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan during the Plan Year (calculated by taking into account Before-Tax Contributions on Bonuses that became payable during the Plan Year, regardless of when such Bonuses were earned), plus the maximum amount of elective deferrals subject to matching under the RSP for the Plan Year (taking into account Code §§402(g), 414(v) and 401(a)(17), as applicable), minus 3% of the Participant's Compensation paid during the Plan Year, but not less than zero; and (B) 3% of the Participant's Compensation payable during the Plan Year (taking into account Bonuses that became payable during the Plan Year, regardless of when such Bonuses were earned); minus

(3) the maximum matching contribution the Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(c) **Nicor Participants**. For each Active Participant who is a Nicor Participant (as defined in the RSP), on whose behalf a Participating Company has made any Before-Tax Contributions to the Plan for the Plan Year, such Participating Company shall make a Matching Contribution equal to:

(1) the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan during the Plan Year (but excluding all Before-Tax Contributions made from the Participant's Bonus), plus the maximum amount of elective deferrals and after-tax contributions subject to matching under the RSP for the Plan Year (taking into account Code §§402(g), 414(v) and 401(a)(17), as applicable), and (B) 3% of the Participant's Compensation, excluding all Bonuses, payable during the Plan Year; plus

(2) 75% of the lesser of (A) the sum of the Participant's Before-Tax Contributions under this Plan during the Plan Year (but excluding all Before-Tax Contributions made from the Participant's Bonus), plus the maximum amount of elective deferrals and after-tax contributions subject to matching under the RSP for the Plan Year (taking into account Code §§402(g), 414(v) and 401(a)(17), as applicable), minus 3% of the Participant's Compensation, excluding all Bonuses, paid during the Plan Year, but not less than zero; and (B) 3% of the Participant's Compensation, excluding all Bonuses, payable during the Plan Year; minus

(3) the maximum matching contribution the Active Participant could receive under the RSP for such Plan Year (without regard to whether the Active Participant actually receives such maximum matching contribution).

(d) **Timing.** Matching Contributions shall be made to the Plan once each year within the period of two months following the last day of the Plan Year to which the Matching Contributions relate.

2. Except as provided herein, the Plan shall remain in full force and effect.

IN WITNESS WHEREOF, the Committee has caused its duly authorized member to execute this Amendment on the date written below.

ADMINISTRATIVE COMMITTEE

By: /s/ Wendy Henderson

Name: Wendy Henderson

Date: December 20, 2013

Exhibit 12

AGL Resources Inc.
Statement Setting Forth Ratio of Earnings to Fixed Charges

Dollars in millions	Fiscal 2013	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Earnings before income taxes	$ 522	$ 450	$ 311	$ 390	$ 384
Add:					
Fixed charges (see "B" below)	200	203	145	123	115
Amortization of capitalized interest (1)	-	-	1	-	-
Distributed income of equity investees	3	14	-	-	-
Less:					
Interest capitalized (1)	-	(1)	(1)	(5)	(3)
Noncontrolling interest in pre-tax income of subsidiaries that have not incurred fixed charges	(18)	(15)	(14)	(16)	(27)
Adjusted earnings (A)	$ 707	$ 651	$ 442	$ 492	$ 469
Fixed charges					
Interest on long-term debt	$ 182	$ 177	$ 101	$ 109	$ 98
Other interest, including amortized premiums, discounts and capitalized expenses related to indebtedness liability	6	13	37	7	10
Estimated interest components of rentals	12	13	7	7	7
Total fixed charges (B)	$ 200	$ 203	$ 145	$ 123	$ 115
Ratio of earnings to fixed charges (A)/(B)	3.54	3.21	3.05	4.00	4.08

(1) Includes interest capitalized and related amortization for our nonregulated segments.

Exhibit 21

Subsidiaries of AGL Resources Inc. (1)

Following is a listing of the significant subsidiaries as of December 31, 2013

Name of Subsidiary	**State of Incorporation**
AGL Capital Corporation	Nevada
Atlanta Gas Light Company	Georgia
Georgia Natural Gas Company	Georgia
SouthStar Energy Services LLC (2)	Delaware
Northern Illinois Gas Company (3)	Illinois
Pivotal Utility Holdings, Inc. (4)	New Jersey

(1) The names of certain subsidiaries have not been included because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary.
(2) 85% owned by Georgia Natural Gas Company.
(3) Doing business as Nicor Gas Company.
(4) Includes operations of three natural gas utilities: Elizabethtown Gas (New Jersey), Florida City Gas (Florida) and Elkton Gas (Maryland).

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Forms S-8 (Nos. 33-62155, 333-26961, 333-26963, 333-86983, 333-86985, 333-75524, 333-97121, 333-104701, 333-115044, 333-127161, 333-136241, 333-142575, 333-154965, 333-174375, 333-178497, and 333-178775) and S-3 (Nos. 333-182983 and 333-190280) of AGL Resources Inc. of our report dated February 6, 2014 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K**.**

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 6, 2014

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

CERTIFICATIONS

I, John W. Somerhalder II, certify that:

1. I have reviewed this annual report on Form 10-K of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 6, 2014

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

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

CERTIFICATIONS

I, Andrew W. Evans, certify that:

1. I have reviewed this annual report on Form 10-K of AGL Resources Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 6, 2014

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

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

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

The undersigned, as the chief executive officer of AGL Resources Inc., certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) the Form 10-K for the year ended December 31, 2013 (the "Report"), which accompanies this certification, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of AGL Resources Inc.

Date: February 6, 2014

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

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

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002
(18 U.S.C. SECTION 1350)

The undersigned, as the chief financial officer of AGL Resources Inc., certifies, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my knowledge:

(1) the Form 10-K for the year ended December 31, 2013 (the "Report"), which accompanies this certification, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934; and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of AGL Resources Inc.

Date: February 6, 2014

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