AGL RESOURCES INC
Form 10-K
February 12, 2015

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, 2014

Commission File Number 1-14174

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

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

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 2014 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 2015 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 30, 2014, as reported by the New York Stock Exchange), was $6,574,107,387.

The number of shares of AGL Resources Inc.'s common stock outstanding as of February 4, 2015 was 119,656,937

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2015 Annual Meeting of Shareholders (Proxy Statement) to be held on April 28, 2015, 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
Atlantic Coast Pipeline	Atlantic Coast Pipeline, LLC
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
Compass Energy	Compass Energy Services, Inc., which was sold in 2013
Dalton Pipeline	A 50% undivided ownership interest in a pipeline facility in Georgia
EBIT	Earnings before interest and taxes, the primary measure of our reportable 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
Horizon Pipeline	Horizon Pipeline Company, LLC
HVAC	Heating, ventilation and air conditioning
Illinois Commission	Illinois Commerce Commission, the state regulatory agency for Nicor Gas
Jefferson Island	Jefferson Island Storage & Hub, LLC
LDC	Local Distribution Company
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
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
PennEast Pipeline	PennEast Pipeline Company, LLC
PGA	Purchased Gas Adjustment
Piedmont	Piedmont Natural Gas Company, Inc.
Pivotal Home Solutions	Nicor Energy Services Company, doing business as Pivotal Home Solutions
PP&E	Property, plant and equipment
S&P	Standard & Poor’s Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SouthStar	SouthStar Energy Services LLC
STRIDE	Atlanta Gas Light’s Strategic Infrastructure Development and Enhancement program
Triton	Triton Container Investments LLC
Tropical Shipping	Tropical Shipping and Construction Company Limited
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
WACC	Weighted average cost of capital
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 segments consist of the following four reportable segments, which are consistent with how management views and manages our businesses.

Distribution Operations	· Operation, construction and maintenance of 80,700 miles of natural gas pipeline and 14 storage facilities to provide safe and cost-effective service of natural gas to residential, commercial and industrial customers · Serves 4.5 million customers across 7 states · Rates of return are regulated by each individual state in return for exclusive franchises
Retail Operations	· Provision of natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice · Serves 628,000 energy customers and 1.2 million service contracts across 15 states
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 · Serves a variety of customers in the natural gas value chain with operations structured to optimize storage and transportation portfolios under a wide range of market conditions through the use of hedging tools that allow us to capture additional value while limiting risk
Midstream Operations	· Consists primarily of high deliverability natural gas storage facilities and select pipelines, enabling the provision of diverse sources of natural gas supplies to our customers

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.

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	Number of customers (in thousands)	Approximate miles of pipe
Nicor Gas	Illinois	2,195	34,100
Atlanta Gas Light	Georgia	1,560	32,600
Virginia Natural Gas	Virginia	287	5,500
Elizabethtown Gas	New Jersey	281	3,200
Florida City Gas	Florida	105	3,600
Chattanooga Gas	Tennessee	63	1,600
Elkton Gas	Maryland	6	100
Total		4,497	80,700

Competition and Customer Demand

Our utilities do not compete with other distributors of natural gas in their exclusive franchise territories, but face competition from other energy products. Our principal competitors are electric utilities and fuel oil and propane providers serving the residential, commercial and industrial markets throughout our service areas for our customers who are considering switching from a natural gas appliance. Accordingly, 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 use the chosen energy source for the life of the equipment. Customer demand for natural gas could be affected by numerous factors, including:

- change in the availability or price of natural gas and other forms of energy;
- general economic conditions;
- energy conservation, including state-supported energy efficiency programs;
- legislation and regulations; and
- the cost and capability to convert from natural gas to alternative energy products;

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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 might use natural gas, 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.

Recent advances in natural gas drilling in shale producing regions in the U.S. have resulted in historically high supplies of natural gas and historically low prices for natural gas. This dynamic has provided solid cost advantages for natural gas when compared to electricity, fuel oil and propane and opportunities for growth for our businesses.

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 in states where this is approved by the state commission. We also contract for transportation and storage services from interstate pipelines that are regulated by the FERC. 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 consistently 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.

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 when billing customers. 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 that limit our exposure to weather changes within typical ranges in these utilities' respective service areas.

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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 natural gas 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. 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 2014 return on rate base (2)	8.56%	7.80%	6.45%	8.22%	5.37%	7.94%
Authorized return on equity (1)	10.17%	10.75%	10.00%	10.30%	11.25%	10.05%
Estimated 2014 return on equity (2)	12.12%	10.16%	8.77%	11.52%	8.41%	11.19%
Authorized rate base % of equity (1)	51.07%	51.00%	45.36%	47.89%	36.77%	46.06%
Rate base included in 2014 return on equity (2)	$ 1,561	$ 2,315	$ 590	$ 519	$ 182	$ 104
Weather normalization (3)			ü	ü		ü
Decoupled or straight-fixed-variable rates (4)		ü	ü			ü
Regulatory infrastructure program rates (5)	ü	ü	ü	ü		
Bad debt rider (6)	ü		ü			ü
Synergy sharing policy (7)		ü				
Energy efficiency plan (8)	ü		ü	ü	ü	ü
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, 2014.

(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.

(5) Includes programs that update or expand our distribution systems and liquefied natural gas facilities.

(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 purchased gas adjustment (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 current Nicor Gas customers through our PGA mechanism based upon natural gas throughput over 12 months beginning in July 2013. Approximately $43 million was refunded during 2014 and $29 million was refunded during 2013. For more information on the PBR plan, see Note 11 to our consolidated financial statements under Item 8 herein.

In August 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services, requesting refunds of $18 million and $22 million, respectively. We filed surrebuttal testimony in December 2014 disputing that any refund is due, as Nicor Gas was authorized to enter into these transactions and revenues associated with such reduced rate payer costs as either credits to the PGA or reductions to base rates were consistent with then-current Illinois Commission orders governing these activities. We believe these claims engage in hindsight speculation, which is expressly prohibited in a prudence review examination, and we intend to vigorously defend against these claims. Evidentiary hearings are scheduled for March 2015. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Nicor Gas' first three-year energy efficiency program, which outlines energy efficiency program offerings and therm reduction goals for a three-year period, ended in May 2014. Nicor Gas spent $125 million on the program and reduced customer usage by an estimated 46 million therms. Additionally, in May 2014, the Illinois Commission approved Nicor Gas' second energy efficiency program, Energy Smart Plan, with expected spending of $93 million over a three-year period that began in June 2014. Nicor Gas spent $14 million on this new program in 2014.

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Atlanta Gas Light In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. In September 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several Marketers that included a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. The Georgia Commission approved the stipulation in December 2014. Over the five-year period, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, will be used to resolve 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light is obligated to resolve 25% and we have recorded a reserve in our Consolidated Statements of Financial Position representing the future estimated cost to purchase the approximately 1.15 Bcf of natural gas. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all certificated Marketers through charges for system retained storage gas as it is used by the certificated Marketers.

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 this filing to be discussed by the staff of the Georgia Commission in February 2015.

We expect Atlanta Gas Light to file a petition with the Georgia Commission for approval of a rate increase to our STRIDE surcharge associated with the final accounting of our pipeline replacement program (PRP) in February 2015. The proposed rate increase is designed to collect the unrecovered revenue requirement of the program and is in accordance with the requirements set forth by the Georgia Commission that allows Atlanta Gas Light to make a true-up filing at the end of the program to recover the actual costs of the program. The program ended December 31, 2013.

Virginia Natural Gas In April 2014, the Governor of Virginia signed into law legislation that enables the state's natural gas utilities, including Virginia Natural Gas, to acquire long-term supplies of natural gas and make capital investments to facilitate the delivery of low-cost shale and coal-bed methane gas to Virginia homeowners and businesses. Under the terms of the new statute, Virginia Natural Gas could enter into commercial agreements to obtain up to 25% of its annual firm sales demand for natural gas through long-term contracts or investments such as purchases of reserves. Recovery on investments would be based upon the utility's authorized return on rate base, which would flow through the PGA mechanism or a similar mechanism. The new statute also allows us to build pipelines and other infrastructure that deliver shale and coal-bed methane gas into the state's markets that seek to reduce natural gas supply costs or reduce price volatility for consumers. All filings under this legislation require approval by the Virginia Commission, and we have not made any filings to date.

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 available pipeline and storage capacity to improve the overall cost of supplying gas to the utility customers. Currently, 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 2014, Sequent has made sharing payments under these agreements totaling $272 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	2014	2013	2012	Expiration Date
Elizabethtown Gas	$18	$6	$5	March 2019
Virginia Natural Gas	14	4	3	March 2016
Atlanta Gas Light	13	6	5	March 2017
Florida City Gas	1	1	1	(1)
Chattanooga Gas	1	1	1	March 2018
Total	$47	$18	$15	

(1) The term of the agreement is evergreen and renews automatically each year unless terminated by either party.

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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.

Our firm contracts range in duration from 3 to 25 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. During 2014, we announced our participation in three pipeline projects that will provide access to shale gas in the proximity of our service territories. We have entered into longer-term contracts in connection with these pipeline projects, which resulted in an increase in the duration of our firm contracts compared to prior years. 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.

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 2014 for our distribution operations segment were $715 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 2015 are discussed in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Liquidity and Capital Resources.”

	Program	Program details	Recovery	Expenditures in 2014 (in millions)	Expenditures since project inception (in millions)	Miles of pipe installed since project inception	Scope of program (total miles)	Program duration (years)	Last year of program
Atlanta Gas Light	Integrated Vintage Plastic Replacement Program (i-VPR)	(1)	Rider	$ 62	$ 67	194	756	4	2017
Atlanta Gas Light	Integrated System Reinforcement Program (i-SRP)	(2)	Rider	13	264	n/a	n/a	8	2017
Atlanta Gas Light	Integrated Customer Growth Program (i-CGP)	(3)	Rider	7	47	n/a	n/a	8	2017
		(4)		17	32	71	111	10	2020

Chattanooga Gas	Bare Steel & Cast Iron		Rate Based						
Elizabethtown Gas	Aging Infrastructure Replacement (AIR)	(4)	Rider / Rate Based	32	38	40	130	4	2017
Elizabethtown Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort (ENDURE)	(5)	Rate Based	2	2	4	13	1	2015
Florida City Gas	Galvanized Replacement Program	(6)	Rate Based	1	14	75	111	17	2017
Nicor Gas	Investing in Illinois (Qualified Infrastructure)	(7)(8)	Rider	22	22	13	800	9	2023
Virginia Natural Gas	Steps to Advance Virginia's Energy (SAVE)	(7)	Rider	24	64	127	250	5	2017
Total				$ 180	$ 550	524	2,171		

(1) Early vintage plastic, risk based mid vintage plastic, mid vintage neighborhood convenience.

(2) Large diameter pressure improvement and system reinforcement projects.

(3) New business construction and strategic line extension.

(4) Cast iron and bare steel.

(5) Cast iron and distribution reinforcement.

(6) Galvanized and X-Tube steel. Expenditures and miles reported are post AGL Resources acquisition.

(7) Cast iron, bare steel, mid vintage plastic and risk based materials.

(8) Represents expenditures on qualifying infrastructure that will be placed into service after the rate freeze date, December 9, 2014.

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Atlanta Gas Light Our STRIDE program is comprised of i-SRP, i-CGP and i-VPR. STRIDE includes a surcharge on firm customers that provides recovery of the revenue requirement for the ongoing programs and the PRP, which ended on December 31, 2013. These infrastructure development, enhancement and replacement programs are used to update and expand distribution systems and liquefied natural gas facilities, improve system reliability and meet operational 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. Under I-SRP, we must 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. 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.

A new $260 million, four-year STRIDE program was approved in December 2013, of which $214 million is for i-SRP related projects and $46 million is 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 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 is being funded through an increase in the STRIDE monthly rider surcharge per customer of $0.48 through December 2014, which increases to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016. This surcharge will continue through 2025. If the Georgia Commission elects to extend the i-VPR program beyond 2017, the remaining vintage plastic mains in our system could be considered for replacement through the program over the next 15 - 20 years as it reaches the end of its useful life. In December 2014, the Georgia Commission approved a stipulation between Atlanta Gas Light and the staff of the Georgia Commission that allows for the recovery or refund of certain operation and maintenance expenses associated with the i-VPR program that are above or below an established baseline amount of $7 million.

Nicor Gas In July 2013, Illinois enacted legislation that allows 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. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we may implement rates under the program effective in March 2015. Our filing included a project scope with cost estimates for three years of $171 million in 2015, $173 million in 2016 and $171 million in 2017. Our current project scope includes cost estimates that are approximately $200 million in 2015 and $250 million in each of 2016 and 2017. These expenditure levels represent approximately 1.3%, 3.5% and 4.0% of annual average base rate revenues for 2015, 2016 and 2017, respectively, which are all within the program requirements.

Elizabethtown Gas Our extension of the enhanced infrastructure program in 2013 allowed for infrastructure investment of $115 million over four years, effective as of September 2013, and is focused on the replacement of aging cast iron of our pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a weighted average cost of capital (WACC) of 6.65%. We agreed to file a general rate case by September 2016. Prior accelerated infrastructure investments under this program will be recovered through a permanent adjustment to base rates.

In July 2014, the New Jersey BPU approved 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 from August 2014 through September 2015. The plan allows Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program.

Virginia Natural Gas The SAVE program, which was approved in August 2012, 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 for costs associated with certain infrastructure replacement programs. This five-year program 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. The second year performance rate update was approved by the Virginia Commission in July 2014 and became effective as of August 2014.

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 MGP 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 628,000 natural gas commodity customers and 1.2 million service contracts. Companies within our retail operations segment include SouthStar and Pivotal Home Solutions.

SouthStar is one of the largest retail natural gas marketers in the United States and 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. See Note 10 to our consolidated financial statements under Item 8 herein for more information.

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. We have a portable product suite, which can be offered in most geographies and markets. Pivotal Home Solutions serves customers in several states, primarily Illinois, Indiana and Ohio. Additionally, we are working to expand product offerings to customers in our affiliate companies to enhance the customer experience and retention, as well as promote switching to natural gas from other energy products, such as electricity, propane or fuel oil.

Competition and Operations Our retail operations business competes with other energy marketers to provide natural gas and related services to customers in the areas in which they operate. In the Georgia market, SouthStar operates as Georgia Natural Gas and is the largest of 12 Marketers in the state, with average customers of nearly 500,000 over the last three years and market share of approximately 31% during 2014.

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. However, SouthStar has utilized new products and marketing partnerships to stabilize its portfolio mix in Georgia and has entered new retail markets to position the company for future growth.

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 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, which 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.

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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, a non-regulated retail natural gas business supplying commercial and industrial customers. Under the terms of the purchase and sale agreement, we received an initial cash payment of $12 million, resulting in a pre-tax gain of $11 million ($5 million net of tax) and were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received a cash payment of $4 million, resulting in the recognition of a $3 million gain. We have a five-year agreement through April 2018 to supply natural gas to our former customers.

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 and natural gas producers located in the areas of the country in which we operate. We are also focused on building our fee-based services as 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 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 the 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 the related physical storage and transportation transactions occur and are recognized in earnings. 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 protect the operating revenue that we will ultimately realize when the stored gas is actually sold.

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 natural 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.

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. In addition to natural gas storage, this segment also includes our developing LNG business, which focuses on LNG for transportation, and select pipeline investments that are outside of state regulatory jurisdiction.

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Pipelines During 2014, we entered into three pipeline agreements, as indicated in the following table, which are subject to regulatory approvals. These projects, along with our existing pipelines discussed below, will support our efforts to provide diverse sources of natural gas supplies to our customers, resolve current and long-term supply planning for new capacity, enhance system reliability and generate economic development in the areas served. The pipeline development projects will be financed through a combination of commercial paper and long-term debt issuances. See Note 10 to the consolidated financial statements under Item 8 herein for additional information.

Dollars in millions	Miles of pipe	Expected capital expenditures (1)	Ownership interest (1)	Scheduled year of completion	Expected FERC filing process File date	Approval date
Dalton Pipeline (2)	106	$ 210	50 %	2017	2015	2016
PennEast Pipeline (3)	108	200	20 %	2017	2015	2016
Atlantic Coast Pipeline (4)	550	260	5 %	2018	2015	2016
Total	764	$ 670				

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

(2) In April 2014, we entered into two agreements associated with the construction of the Dalton Lateral Pipeline, which will serve as an extension of the Transco pipeline system and provide additional natural gas supply to our customers in Georgia. The first is a construction and ownership agreement and the second is an agreement to lease our ownership in this lateral pipeline extension once it is placed in service.

(3) In August 2014, we entered into a joint venture to construct and operate a natural gas pipeline that will transport low-cost natural gas from the Marcellus Shale area to our customers in New Jersey. We believe this will alleviate takeaway constraints in the Marcellus region and help mitigate some of the price volatility experienced during the past winter.

(4) In September 2014, we entered into a joint venture to construct and operate a natural gas pipeline that will run from West Virginia through Virginia and into eastern North Carolina to meet the region's growing demand for natural gas. The proposed pipeline project is expected to transport natural gas to our customers in Virginia.

Magnolia Enterprise Holdings, Inc. This wholly owned subsidiary operates a pipeline that provides our Georgia customers diversification of natural gas sources and increased reliability of service in the event that supplies coming from other supply sources are disrupted.

Horizon Pipeline This 50% owned joint venture with Natural Gas Pipeline Company of America operates an approximate 70 mile natural gas pipeline stretching from Joliet, Illinois to near the Wisconsin/Illinois border. Nicor Gas has contracted for approximately 80% of Horizon Pipeline's total throughput capacity of 0.38 Bcf under an agreement expiring in May 2025.

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 2014, expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to continue in 2015 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 continues to improve, 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 developing new storage facilities, including construction time and other costs, federal, state and local permitting and approvals and suitable and available sites, to capitalize on these expected improvements in market conditions.

Other

Our “other” non-reportable segment includes aggregated subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our reportable segments. This segment includes our investment in Triton, which was not part of the sale of Tropical Shipping that closed on September 1, 2014. See Note 14 to the consolidated financial statements under Item 8 herein for additional information on the disposition of Tropical Shipping. AGL Services Company is a service company we established to provide certain centralized shared services to our reportable segments. We allocate substantially all of AGL Services Company’s operating expenses and interest costs to our reportable segments in accordance with state regulations. Our EBIT results include the impact of these allocations to the various reportable segments.

AGL Capital, our wholly owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt instruments and other financing arrangements.

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Employees

As of December 31, 2014, we had approximately 5,165 employees, all of whom were in the U.S. The decrease in total employees from 2013 primarily resulted from the sale of our Tropical Shipping business in 2014.

The following table provides information about our natural gas utilities' collective bargaining agreements, which represent approximately 33% of our total employees.

	Number of employees	Contract expiration date
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19) (1)	1,386	February 2017
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50) (2)	139	May 2015
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	171	November 2015
Total	1,696	

(1) Nicor Gas' collective bargaining agreement expired in February 2014, and a new agreement was ratified in April 2014. The new agreement provides for additional operational enhancements and changes to certain benefits, but does not have a material effect on our consolidated financial statements.
(2) 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 done historically, 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 2015 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 17, 2015, and we will make it available on our website as soon as reasonably practicable thereafter. 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 “potential,” “predict,” “project,” “proposed,” “seek,” “should,” “target,” “would” or similar expressions. You are cautioned not 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 changes 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; 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.

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Risks Related to Our Business

Our business is subject to substantial regulation by federal, state and local regulatory authorities. Adverse determinations by them and, in some instances, the absence of timely determinations, could adversely affect our business.

At the federal level, our business is regulated by the FERC. At the state level, our business is regulated by public service commissions or similar authorities, as well as local governing bodies with respect to certain issues.

Depending upon the jurisdiction, these regulatory authorities are generally entitled to review and approve many aspects of our operations, including the rates that we charge customers (including the recovery of costs for pipeline replacement and other capital projects), the rates of return on our equity investments in our operating companies, how we operate our business, and the interaction between our regulated operating companies and other subsidiaries that might provide products or services to those companies. In addition, our operating companies are generally subject to franchise agreements that entitle them to provide products and services.

While applicable law often provides a framework for the approvals that we need, the regulatory authorities generally have broad discretion. Moreover, in some jurisdictions, the regulatory process involves elected officials and is subject to inherent political issues, which can impact the approvals that we request. As a result, we may or may not be able to obtain the approvals that we request, the timing of obtaining those approvals can be uncertain, and the approvals can be subject to conditions that may or may not be favorable to our business. Should we not be able to obtain the rate increases that we request in a timely manner, should we not be able to fully recover the costs that we incur, or should we otherwise not obtain favorable approvals for the operation of our business, our business will be adversely impacted.

In addition, the regulatory environment in which we operate has increased in complexity over time, and further change is likely in many jurisdictions. These changes may or may not be favorable to our business. As the regulatory environment grows in complexity, inadvertent noncompliance is increasingly a greater risk. Noncompliance can, depending upon the circumstances, result in fines, penalties or other enforcement action by regulatory authorities, as well as damage our reputation and standing in the community, all of which would adversely impact our business.

Energy prices can fluctuate widely and quickly. To the extent that we have not anticipated and planned for those changes, our business can be adversely affected.

Recently, the price for natural gas and competing energy sources, such as oil, have fluctuated widely. Generally, we pass through changes in prices to the customers of our operating companies, and we have a process in place to continually review the adequacy of our utility gas rates and to take appropriate action with the applicable regulatory authorities. However, there is an inherent regulatory lag in adjusting rates and, in an increasing price environment, we have to bear the increased costs on an interim basis. We also have to incur additional financing costs as a result of purchasing more expensive gas.

In addition, increases in gas prices, both in absolute terms and relative to alternative energy sources, negatively impacts demand, the ability of customers to pay their utility bills and the timing of those payments (which lead to larger accounts receivable and greater bad debt expense) and various other factors. While the impact of some of these factors can be passed through to customers, there is generally a delay in that process that can adversely affect our business.

As noted below, for some portions of our business, we hedge the risk of price changes through the purchase of futures contracts and other means. These efforts, while designed to minimize the adverse impact of price changes, cannot assure that result. As a result, we retain exposure to price changes that can, in a volatile energy market, be extremely material and can adversely affect our business.

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Variations in weather beyond what we have planned for can adversely impact our business.

A substantial portion of our revenue is derived from the transportation or sale of gas for space heating purposes. We plan for the demand of gas for this purpose based upon historical weather patterns and resulting demand. Where weather varies significantly beyond the range that we have planned for, it can impact us in many ways, including through increasing or decreasing the demand for gas, the cost of gas to us, and the availability, sufficiency and cost of transportation and storage capacity.

A decrease in the availability of adequate pipeline transportation capacity due to weather conditions or otherwise could adversely impact our business. We depend upon having access to adequate transportation and storage capacity for virtually all of our operations. A decrease in interstate pipeline capacity available to us, or an increase in competition for interstate pipeline transportation and storage capacity (e.g., even as a result of weather in regions that we do not significantly serve) could reduce our normal interstate supply of gas or cause rates to fluctuate.

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, although 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. Outside of those ranges, our financial exposure is greater.

We also have decoupled rate designs, including straight-fixed-variable, at Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas that 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.

At Nicor Gas, approximately 60% 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 operating income and cash flow. For example, we estimate that a 100 degree-day variation from normal weather of 5,752 Heating Degree Days impacts Nicor Gas' margin, net of income taxes, by approximately $1 million under its current rate structure. For our weather risk associated with Nicor Gas, we utilize weather derivatives to reduce, but not eliminate, the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois. For more information, see Note 2 to the consolidated financial statements under Item 8 herein.

Changes in weather conditions may also impact SouthStar's earnings. As a result, SouthStar uses a variety of weather derivative instruments to mitigate 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 mitigate the effects of unusually warm or cold weather.

Similarly, changes in weather conditions may also impact wholesale services' earnings. In addition to the impacts described above, weather impacts the ability of our wholesale services segment to capture value from location and seasonal spreads. Through the acquisition of natural gas and hedging of natural gas prices, wholesale services reduces some of the weather-related risks that it faces, but it cannot eliminate all of those risks.

Our retail energy businesses in Illinois, Nicor Solutions and Nicor Advanced Energy, offer utility-bill management products that mitigate and/or eliminate the risks of variations in weather to customers. We hedge this risk to reduce any adverse effects to us from weather variations.

We are subject to environmental regulation and our costs to comply are significant. Any changes in existing environmental regulation could adversely affect our business.

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. Failure to comply with these laws and regulations and failure to obtain any required permits and licenses may expose us to material fines, penalties or interruptions in our 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. A number of environmental issues may exist with respect to MGP's. For more information regarding these obligations, see Note 11 to the consolidated financial statements under Item 8 herein. Claims against us under environmental laws and regulations could result in material costs and liabilities.

Existing environmental laws and regulations could also 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 that could have a material adverse effect on our business.

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 may also 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, 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 regulatory and financial risks related to the impact of 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 climate change to increased levels of greenhouse gases, including carbon dioxide and methane, 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 and methane, differently than under historical precedent. 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 the EPA to adopt performance standards to regulate greenhouse gas emissions from power plants. Specifically, the Presidential Memorandum directs the 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 the 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 relative to other traditional fuels, future carbon constraints may 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. However, methane, the primary constituent of natural gas, is a potent greenhouse gas. Future regulation of methane could likewise result in increased costs to us and affect the demand for natural gas, as well as the prices we charge our customers and the competitive position of natural gas.

Any adoption of regulation 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 business.

Glossary

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 explosions, and mechanical problems, which 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.

Our wholesale services segment competes for sales with national and regional full-service energy providers, energy merchants and producers, and pipelines 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 2015.

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 counterparties. Despite performing credit analyses prior to extending credit and seeking to implement netting agreements, if the counterparties fail to perform and any collateral Nicor Gas or Sequent has secured is inadequate, we could experience material financial losses.

Further, Sequent has a concentration of credit risk with a limited number of parties. 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 could be significant.

We have accounts receivable collection risks in Georgia due to a concentration of credit risks related to the provision of natural gas services to approximately 12 Marketers. As a result, Atlanta Gas Light depends on a limited number of customers for a significant portion of its revenues.

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 LDC's, 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, 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 "VaR" 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.

The cost of providing retirement plan benefits to eligible current and former employees is subject to changes in the performance of investments, demographics, and various other factors and assumptions. These changes may have a material adverse effect on us.

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 will have an 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 federal funding requirements.

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 Welfare Obligations" and Note 6 to the consolidated financial statements under Item 8 herein.

Natural disasters, terrorist activities and similarly unpredictable events could adversely affect our businesses.

Natural disasters may damage our assets, interrupt our business operations and adversely impact the demand for natural gas. 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. The insurance industry has been disrupted by these types of events. As a result, the availability of insurance covering risks against which we and similar businesses typically insure may be limited or insufficient. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms. In addition, 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.

Work stoppages could adversely impact our businesses.

Some 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 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, restrict or prohibit certain activities, which could 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, could lead to system disruptions or generate facility shutdowns. If a cyber-attack or security breach were to occur, our business, results of operations and financial condition could be materially adversely affected. In addition, a cyber-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 could expose us to liability to our customers, vendors, financial institutions and others. In addition, 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, although, to our knowledge, we did not have any material security breaches in 2014.

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

We have pursued acquisitions to complement or expand our business, divestures and other strategic transactions in the past and expect to in the future. 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 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. Any failure to successfully integrate businesses that we acquire in an efficient and effective manner could have a material adverse effect on us. Similarly, we may divest portions of our business, which may also have material and adverse effects.

We assess goodwill 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 2014 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 2014.

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. 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, WACC 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.

Risks Related to Our Corporate and Financial Structure

We depend on access to the capital and financial markets to fund our business. 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 sources 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.

A downgrade in our credit rating would require us to pay higher interest rates and 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. 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" herein. 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" herein for additional information.

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 into 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 values of these contracts.

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.

Our credit facilities 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.

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 customers in our service areas. These systems consist primarily of distribution and transmission mains, compressor stations, peak shaving/storage plants, service lines, meters and regulators. At December 31, 2014, our distribution operations segment owned approximately 80,700 miles of underground distribution and transmission mains, which are located on easements or rights-of-way that generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair, and believe that our distribution systems are in good condition.

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 help mitigate the risk associated with seasonal price movements.

We have five LNG plants located in Georgia, New Jersey and Tennessee with LNG storage capacity of approximately 7.6 Bcf. 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 that are operated by our midstream operations segment. Jefferson Island operates a storage facility in Louisiana currently consisting of two salt dome gas storage caverns. Golden Triangle operates a storage facility in Texas consisting of two salt dome caverns. Central Valley operates a depleted field storage facility in California. In addition, we have an LNG facility in Alabama that produces LNG for Pivotal LNG, a wholly owned subsidiary, to support its business of selling LNG as a substitute fuel in various markets. For additional information on our storage facilities, see Item 1, "Business" under the caption “Midstream Operations” herein.

Offices

All of our reportable 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.

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 February 4, 2015, there were 21,551 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2014 and 2013 is as follows:

	Sales price of common stock		Cash dividend per common share		Sales price of common stock		Cash dividend per common share
Quarter ended:	High	Low		Quarter ended:	High	Low	
March 31, 2014	$49.84	$45.17	$0.49	March 31, 2013	$42.37	$38.86	$0.47
June 30, 2014	55.10	48.29	0.49	June 30, 2013	44.85	41.21	0.47
September 30, 2014	55.30	48.72	0.49	September 30, 2013	47.00	41.94	0.47
December 31, 2014	56.67	50.10	0.49	December 31, 2013	49.31	44.56	0.47
			$1.96				$1.88

We have paid 268 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” herein. 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.

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, 2014.

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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 which should be read in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data" herein. Additionally, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" herein for a discussion of the primary factors impacting the changes in our results of operations for the periods reflected in our Consolidated Statements of Income. The operations of our former Tropical Shipping business, which was sold during 2014, are reflected as discontinued operations and all prior periods have been recast to reflect the discontinued operations. Material changes from 2013 to 2014 are due primarily to earnings from our wholesale services segment, resulting mainly from colder-than-normal weather and associated natural gas price volatility in 2014. 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	2014	2013	2012	2011	2010
Income statement data					
Operating revenues	$5,385	$4,209	$3,562	$2,305	$2,373
Operating expenses					
Cost of goods sold	2,765	2,110	1,583	1,085	1,164
Operation and maintenance (1)	939	887	816	497	497
Depreciation and amortization	380	397	394	182	160
Nicor merger expenses (1)	-	-	20	57	6
Taxes other than income taxes	208	187	159	57	46
Total operating expenses	4,292	3,581	2,972	1,878	1,873
Gain on disposition of assets	2	11	-	-	-
Operating income	1,095	639	590	427	500
Other income (expense)	14	16	24	7	(1)
EBIT	1,109	655	614	434	499
Interest expense, net	179	170	183	134	109
Income before income taxes	930	485	431	300	390
Income tax expense	350	177	157	121	140
Income from continuing operations	580	308	274	179	250
(Loss) income from discontinued operations, net of tax	(80)	5	1	-	-
Net income	500	313	275	179	250
Less net income attributable to the noncontrolling interest	18	18	15	14	16
Net income attributable to AGL Resources Inc.	$482	$295	$260	$165	$234
Amounts attributable to AGL Resources Inc.					
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259	$165	$234
(Loss) income from discontinued operations, net of tax	(80)	5	1	-	-
Net income attributable to AGL Resources Inc.	$482	$295	$260	$165	$234

Per common share information										
Diluted weighted average common shares outstanding	119.2		118.3		117.5		80.9		77.8	
Diluted earnings (loss) per common share										
Continuing operations	$4.71		$2.45		$2.20		$2.04		$3.00	
Discontinued operations	(0.67	)	0.04		0.01		-		-	
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04		$2.49		$2.21		$2.04		$3.00	
Dividends declared per common share	$1.96		$1.88		$1.74		$1.90		$1.76	
Dividend payout ratio	49	%	76	%	79	%	93	%	58	%
Dividend yield (2)	3.6	%	4.0	%	4.4	%	4.5	%	4.9	%
Price range:										
High	$56.67		$49.31		$42.88		$43.69		$40.08	
Low	$45.17		$38.86		$36.59		$34.08		$34.21	
Close (3)	$54.51		$47.23		$39.97		$42.26		$35.85	
Market value (3)	$6,522		$5,615		$4,711		$4,946		$2,800	
Statements of Financial Position data (3)										
Total assets (4)	$14,909		$14,550		$14,070		$13,862		$7,481	
Property, plant and equipment – net	9,090		8,643		8,205		7,741		4,396	
Long-term debt	3,802		3,813		3,553		3,578		1,971	
Total equity	3,828		3,613		3,391		3,305		1,809	
Financial ratios (3)										
Debt	57	%	58	%	59	%	60	%	60	%
Equity	43	%	42	%	41	%	40	%	40	%
Total	100	%	100	%	100	%	100	%	100	%
Return on average equity	13.0	%	8.4	%	7.8	%	6.4	%	12.9	%

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

(2) 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.

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

(4) Amounts for all periods include assets held for sale, which reflect the assets of our former Tropical Shipping business.

Glossary

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

Executive Summary

We are an energy services holding company whose principal business is the distribution of natural gas in seven states – Illinois, Georgia, Virginia, New Jersey, Florida, Tennessee and Maryland – through our seven natural gas distribution utilities. We are also involved in several other businesses that are complementary to the distribution of natural gas. We have four reportable segments that consist of the following – distribution operations, retail operations, wholesale services and midstream operations – and one non-reportable segment – other. These segments are consistent with how management views and operates our business. Amounts shown in this Item 7, unless otherwise indicated, exclude assets held for sale and discontinued operations. See Note 14 to our consolidated financial statements under Item 8 herein for additional information. The following table provides certain information on our segments.

	EBIT			Assets			Capital expenditures		
	2014 (1)	2013	2012	2014	2013	2012	2014	2013	2012
Distribution operations	52 %	84 %	84 %	81 %	82 %	82 %	93 %	93 %	84 %
Retail operations	12	20	18	5	5	4	1	1	1
Wholesale services	38	-	-	9	8	9	-	-	-
Midstream operations	(1)	(2)	2	5	5	5	2	2	8
Other/intercompany eliminations	(1)	(2)	(4)	-	-	-	4	4	7
Total	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %

(1) The EBIT in 2014 was impacted by significantly higher-than-normal commercial activity realized in wholesale services, which is not indicative of future performance.

In the third quarter of 2014, we adjusted the accounting treatment for our previously reported non-cash revenue recognition associated with our regulatory infrastructure programs in our distribution operations segment. The adjustments did not affect previously reported operating cash flows, nor are they expected to affect capital expenditure plans or dividend payments. We do not expect these adjustments to impact the levels of return from our infrastructure replacement programs, as all amounts will be recovered in accordance with allowed recovery mechanisms. The adjustments relate only to the timing of recognition and do not impact rates charged to customers. Additionally, we adjusted the amortization of intangible assets for customer relationships and trade names in our retail operations segment to reflect the amortization expense on a basis consistent with the pattern of undiscounted cash flows used to determine their fair values. In November 2014, we amended our 2013 Form 10-K and our Forms 10-Q for the quarters ended March 31, 2014 and June 30, 2014 to revise our financial statements to reflect these adjustments. Our prior-period financial statements included herein reflect these adjustments.

In September 2014, we closed on the sale of Tropical Shipping and received after-tax cash proceeds of approximately $225 million, as well as repatriated $86 million in cash. The transaction resulted in expenses, including taxes, of approximately $80 million or $(0.67) per share in 2014. Tropical Shipping operated as part of our cargo shipping segment and the financial results are classified as discontinued operations. Accordingly, all references to continuing operations exclude the operations of Tropical Shipping. The sale of Tropical Shipping allows us to focus on growing our core business of operating regulated utilities and complementary non-regulated energy businesses and provided us with flexibility around our near-term financing plans. For additional information on our discontinued operations, see

Note 14 to our consolidated financial statements under Item 8 herein.

In 2014, our net income from continuing operations was $580 million, an increase of $272 million compared to income from continuing operations in 2013. This increase was primarily the result of significantly higher commercial activity and net hedge gains at wholesale services, mainly due to natural gas market volatility. This volatility was primarily generated by significantly colder-than normal weather in the first quarter of 2014, which also increased the operating margins at distribution operations and retail operations. Excluding the favorable weather impacts, we also achieved growth in our operating margins during 2014 as a result of targeted acquisition growth in retail operations. Our operating expenses in 2014 were higher compared to 2013 mainly as a result of higher incentive compensation expenses primarily related to higher earnings in 2014.

Our priorities for 2015 are consistent with the direction we have taken the company over the last several 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 conditions. 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. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we will implement rates under the program effective in March 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; expand our warranty businesses 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 and expansion into new markets.

- Wholesale Services: Maximize storage and transportation positions; effectively perform on existing asset management agreements, and expand customer base and maintain cost structure in line with market fundamentals. We anticipate volatility to remain low to moderate in certain areas of our portfolio; however, we expect near-term volatility in the supply-constrained Northeast corridor until expected new pipeline projects are completed and new capacity is placed into service. We continue to position our business to secure sufficient supplies of natural gas to meet the needs of our utility and third-party customers and to hedge natural gas prices to manage costs effectively, reduce price volatility and maintain a competitive advantage.

- Midstream Operations: Optimize storage portfolio, including contracts that have expired or will expire, pursue LNG transportation and natural gas pipeline opportunities and evaluate alternate uses for our storage facilities. In 2014, we announced our participation in three pipeline projects that we expect to provide a diverse source of natural gas to our customers in Georgia, New Jersey and Virginia. Subject to regulatory approvals, construction is expected to begin in the 2016-2017 timeframe with completion targeted in 2017-2018. For additional information on our pipeline projects, see Note 2 and Note 10 to our consolidated financial statements under Item 8 herein and Item 1, "Business" under the caption "Midstream Operations."

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 reportable segments, see Note 13 to our consolidated financial statements under Item 8 herein and Item 1, "Business."

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Results of Operations

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

In millions	2014	2013	2012
Residential	$2,877	$2,422	$2,011
Commercial	861	696	656
Transportation	458	487	474
Industrial	242	180	262
Other (1)	947	424	159
Total operating revenues	$5,385	$4,209	$3,562

(1) Includes significantly higher-than-normal revenues at wholesale services in 2014, which are not indicative of future performance.

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

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

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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	2014	2013	2012
Operating revenues	$5,385	$4,209	$3,562
Cost of goods sold	(2,765)	(2,110)	(1,583)
Revenue tax expense (1)	(130)	(110)	(85)
Operating margin	2,490	1,989	1,894
Operating expenses	(1,527)	(1,471)	(1,369)
Revenue tax expense (1)	130	110	85
Gain on disposition of assets	2	11	-
Nicor merger expenses	-	-	(20)
Operating income	1,095	639	590
Other income	14	16	24
EBIT	1,109	655	614
Interest expense, net	(179)	(170)	(183)
Income before income taxes	930	485	431
Income tax expense	(350)	(177)	(157)
Income from continuing operations	580	308	274
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income	500	313	275
Less net income attributable to the noncontrolling interest	18	18	15
Net income attributable to AGL Resources Inc.	$482	$295	$260
Amounts attributable to AGL Resources Inc.			
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Per common share data			
Diluted earnings per common share from continuing operations	$4.71	$2.45	$2.20
Diluted (loss) earnings per common share from discontinued operations (2)	(0.67)	0.04	0.01
Additional accrual for Nicor Gas PBR issue	-	-	0.04
Transaction costs of Nicor merger	-	-	0.11
Diluted earnings per share - as adjusted	$4.04	$2.49	$2.36

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

(2) In September 2014, we closed on the sale of Tropical Shipping. See Note 14 to our consolidated financial statements under Item 8 herein for additional information.

In 2014, our income from continuing operations attributable to AGL Resources Inc. increased by $272 million, or 94% compared to 2013. This increase was primarily the result of the following:

- Significantly higher commercial activity primarily in the first quarter of 2014, and mark-to-market hedge gains, net of LOCOM adjustments at wholesale services in 2014 from price volatility generated by colder-than-normal weather, which increased operating margin by $462 million compared to 2013.

- Increased operating margin at distribution operations and retail operations of $50 million mainly due to significantly colder-than-normal weather in 2014 compared to slightly colder-than-normal weather in 2013, as well as customer usage and customer growth. We also achieved growth as a result of our 2013 acquisitions and expansion into additional markets at retail operations.
- These increases were partially offset by a decrease in margin of $10 million at midstream operations primarily due to a retained fuel true-up at one of our storage facilities as a result of naturally occurring shrinkage of the caverns, as well as lower contracted firm rates at Jefferson Island and Central Valley.
- Favorability year-over-year was negatively impacted by higher incentive compensation expenses primarily related to higher earnings in 2014 and increased outside services expenses of $49 million, and the $8 million higher pre-tax gain in 2013 related to the sale of Compass Energy.
- Our income tax expense from continuing operations increased by $173 million for 2014 compared to 2013, primarily due to higher consolidated earnings. The increase was primarily a result of increased earnings at wholesale services.

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In 2013, our income from continuing operations attributable to AGL Resources Inc. increased by $31 million, or 12% compared to 2012.

- The overall increase was primarily the result of increased operating margin at distribution operations and retail operations due to weather that was both colder-than-normal and colder than the prior 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 in 2013.
- Our midstream operations segment was unfavorable compared to 2012 due to the $8 million loss associated with the termination of the Sawgrass Storage project in 2013, as well as lower contracted firm rates at Jefferson Island and higher operating expenses at Golden Triangle, Central Valley and Pivotal LNG resulting from full year operations in 2013 as compared to partial year operations in 2012.
- Favorability year-over-year was also 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 higher revenues from colder weather combined with natural gas prices that were higher than the prior year.
- In 2012, we recorded $20 million ($13 million net of tax) of Nicor merger-related expenses.
- In 2013, our interest expense decreased by $13 million compared to 2012. This decrease was the result of overall lower interest rates mostly offset by higher average debt outstanding primarily as a result of issuing $500 million of senior notes in place of variable-rate debt.
- In 2013, our income tax expense increased by $20 million or 13% compared to 2012 primarily due to higher consolidated earnings, as previously discussed.

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

	Normal (1)	2014	2013	2012	2014 vs. 2013 colder (warmer)	2013 vs. 2012 colder (warmer)	2014 vs. normal colder (warmer)	2013 vs. normal colder (warmer)	2012 vs. normal colder (warmer)
Year ended December 31,									
Illinois (2)	5,752	6,556	6,305	4,863	4 %	30 %	14 %	10 %	(15)%

Georgia	2,599	2,882	2,689	1,934	7 %	39 %	11 %	3 %	(26)%
Quarter ended December 31,									
Illinois (2)	2,085	2,103	2,383	1,890	(12)%	26 %	1 %	14 %	(9)%
Georgia	1,014	1,003	1,049	878	(4)%	19 %	(1)%	3 %	(13)%

(1) Normal represents the 10-year average from January 1, 2004 through December 31, 2013, for Illinois at Chicago Midway International Airport and for Georgia at Atlanta Hartsfield-Jackson International Airport, as obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center.

(2) The 10-year average Heating Degree Days 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.

In 2014, we experienced weather in Illinois that was 14% colder-than-normal and 4% colder than 2013. This weather positively impacted our 2014 EBIT at our utilities, primarily at Nicor Gas, by $20 million, and drove an increase of $12 million in 2013 based on 10-year normal weather. Georgia also experienced 11% colder-than-normal weather, and 7% colder weather than the same period last year. Colder-than-normal weather increased EBIT at retail operations by $14 million in 2014 and $9 million in 2013 compared to expected levels based on 10-year normal weather.

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

	Years ended December 31,			2014 vs. 2013 change		2013 vs. 2012 change	
(in thousands)	2014	2013	2012	#	%	#	%
Distribution operations customers (1)	4,497	4,479	4,459	18	0.4 %	20	0.4 %
Retail operations							
Energy customers (2)	628	619	623	9	1 %	(4)	(1)%
Service contracts (3)	1,182	1,127	684	55	5 %	443	65 %
Market share in Georgia	31 %	31 %	32 %		- %		(1)%

(1) In 2014, we implemented a process change at Nicor Gas that adversely impacted our customer count. This had the effect of immaterial growth for Nicor Gas from last year. Excluding Nicor Gas, our customer growth rate for 2014 was 0.8%.

(2) Increase from 2013 to 2014 primarily due to the addition of approximately 33,000 residential and commercial customer relationships acquired in Illinois in June 2013.

(3) Increase from 2012 to 2013 primarily due to acquisition of approximately 500,000 contracts on January 31, 2013.

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We anticipate overall utility customer growth trends for 2014 to continue in 2015 based on an expectation of continuing improvement in the economy and relatively 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.

In 2015, we intend to continue efforts in our retail operations segment to enter into targeted markets and expand energy customers and its service contracts. We anticipate this expansion will provide growth opportunities in future years.

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

	Year ended December 31,				
Distribution operations (In Bcf)	2014	2013	2012	2014 vs. 2013 % change	2013 vs. 2012 % change
Firm (1)	766	720	606	6 %	19 %
Interruptible	106	111	107	(5)%	4
Total	872	831	713	5 %	17 %
Retail operations (In Bcf)					
Georgia firm	41	38	31	8 %	23 %
Illinois	17	9	8	89 %	13 %
Other (includes Florida, Maryland, New York and Ohio)	10	8	8	25 %	-
Wholesale services					
Daily physical sales (Bcf/day)	6.32	5.73	5.54	10 %	3 %

(1) Year-over-year increases are primarily a result of colder weather.

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

Our midstream operations storage business is cyclical, and the abundant supply of natural gas in recent years and the resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. Consistent with our expectations, we had contracts expire in 2014 that were re-subscribed at lower prices as compared to prior years. We anticipate these lower natural gas prices to continue in 2015 as compared to historical averages. We expect the rates at which we re-contract expiring capacity in 2015 to be marginally higher than re-contracting rates in

2014, but still significantly below historical averages. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium as the economy continues to improve, expected exports of LNG occur and/or natural gas demand increases in response to low prices and expanded uses for natural gas. As of the periods presented, the overall monthly average firm subscription rates per facility and amount of firm capacity subscription were as follows:

	December 31, 2014		December 31, 2013	
	Average rates (1)	Firm capacity under subscription (1)	Average rates (1)	Firm capacity under subscription (1)
Jefferson Island	$0.108	4.6	$0.122	5.6
Golden Triangle	0.114	5.0	0.240	2.0
Central Valley	0.062	2.5	0.130	3.0

(1) Rates are per dekatherm. Firm capacity under subscription excludes 7 Bcf contracted by Sequent as of December 31, 2014, at an average monthly rate of $0.050 and 3.5 Bcf as of December 31, 2013, at an average monthly rate of $0.091.

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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	2014	2013	2012	2014	2013	2012	2014	2013 (4)	2012
Distribution operations	$ 1,648	$ 1,615	$ 1,552	$ 1,075	$ 1,083	$ 1,044	$ 581	$ 546	$ 517
Retail operations	311	294	247	179	162	136	132	132	111
Wholesale services	501	39	50	79	53	54	422	(3)	(3)
Midstream operations	31	41	46	50	46	38	(17)	(10)	10
Other (5)	7	8	7	22	25	40	(9)	(10)	(21)
Intercompany eliminations	(8)	(8)	(8)	(8)	(8)	(8)	-	-	-
Consolidated	$ 2,490	$ 1,989	$ 1,894	$ 1,397	$ 1,361	$ 1,304	$ 1,109	$ 655	$ 614

(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” herein. See Note 13 to our consolidated financial statements under Item 8 herein for additional segment information.
(2) Operating margin and operating expenses are adjusted for revenue tax expenses, which are passed through directly to our customers.
(3) Includes $20 million in Nicor merger transaction expenses for 2012 and an $8 million accrual in 2012 for the Nicor Gas PBR issue.
(4) EBIT for 2013 includes an $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.
(5) Our “other” non-reportable segment includes our investment in Triton, which was formerly part of our cargo shipping segment that is now classified as discontinued operations. See Note 14 to our consolidated financial statements under Item 8 herein for additional information.

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. 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. The EBIT of our distribution operations, retail operations and wholesale services segments are seasonal, as indicated in the table below.

	Percent generated during Heating Season	
	Revenues	EBIT
2014	73 %	81 %

2013	68	72
2012	70	76

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.

In millions	2014	2013
EBIT - prior year	$ 546	$ 517
Operating margin		
Increase mainly driven by non-weather-related customer usage and customer growth	22	9
Increased margin as a result of higher customer usage due to colder-than-normal weather	13	36
Increase from regulatory infrastructure programs, primarily at Atlanta Gas Light	10	4
(Decrease) increase primarily as a result of bad debt and energy efficiency program recoveries at Nicor Gas	(12)	19
Decreased gas storage carrying amounts at Atlanta Gas Light	-	(5)
Increase in operating margin	33	63
Operating expenses		
Decreased depreciation expense primarily due to the impact of Nicor Gas' new composite depreciation rate effective August 30, 2013, partially offset by increased PP&E from infrastructure additions and improvements	(22)	(8)
Decreased benefit expenses primarily related to lower pension costs due to change in actuarial gains and losses	(13)	(6)
(Decreased) increased rider expenses primarily as a result of energy efficiency program expenses at Nicor Gas	(12)	19
Increased payroll and variable compensation costs as a result of merit increases and higher earnings	19	37
Increased outside services and other expenses mainly as a result of maintenance programs	11	1
Increase due to weather-related expenses	5	-
Increased bad debt expenses related to colder-than-normal weather primarily at Elizabethtown Gas	4	4
Decreased operation and maintenance expense at Nicor Gas related to the 2012 PBR accrual	-	(8)
(Decrease) increase in operating expenses	(8)	39
(Decrease) increase in other income primarily from STRIDE Projects at Atlanta Gas Light	(6)	5
EBIT - current year	$ 581	$ 546

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Retail Operations

Our retail operations segment, which consists of several businesses that provide energy-related products and services to retail markets, is also 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 2014, our retail operations' EBIT was negatively impacted by $16 million of unrealized hedge losses and LOCOM adjustments.

In millions	2014	2013
EBIT - prior year	$132	$111
Operating margin		
Increase due to acquisitions in January and June 2013	9	35
Increase primarily related to customer usage in Georgia and Illinois due to colder-than-normal weather, net of weather hedges	8	18
Increase primarily related to warranty service contract count and price increases	6	-
Increase primarily related to non-weather related customer usage and customer growth	5	1
Increase (decrease) related to change in gas costs and from retail price spreads	5	(11)
Change in value of derivatives as a result of changes in NYMEX natural gas prices	(13)	1
Change in LOCOM adjustment, net of recoveries	(3)	3
Increase in operating margin	17	47
Operating expenses		
Increased variable compensation costs, outside services, marketing and other	11	-
Increased due to weather-related expenses	3	-
Increased bad debt expenses primarily related to higher natural gas prices	2	3
Increased expenses primarily due to acquisitions in January and June 2013	1	23
Increase in operating expenses	17	26
EBIT - current year	$132	$132

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. We have positioned the business to generate positive economic earnings even under low volatility market conditions. However, when market price volatility increases as we experienced in 2014, we are well positioned to capture significant value and generate stronger results. Results in 2014 for the wholesale services segment were the best in the company's history and not indicative of future performance. 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	2014	2013
EBIT - prior year	$(3)	$(3)
Operating margin		

Change in commercial activity largely driven by the transportation and storage portfolios in the Northeast and Midwest	319	90
Change in value of transportation and forward commodity derivatives from price movements related to natural gas transportation positions	111	(70)
Change in value of storage derivatives as a result of changes in NYMEX natural gas prices	102	(30)
Change in LOCOM adjustment, net of estimated current period recoveries	(66)	3
Decrease due to sale of Compass Energy in May 2013	(4)	(4)
Increase (decrease) in operating margin	462	(11)
Operating expenses		
Increased variable compensation expenses related to higher earnings and slightly higher other costs in 2014	28	3
Decrease due to sale of Compass Energy in May 2013	(2)	(4)
Increase (decrease) in operating expenses	26	(1)
(Decrease) increase in other income, primarily related to the gain on sale of Compass Energy	(11)	10
EBIT - current year	$422	$(3)

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

In millions	2014	2013	2012
Commercial activity recognized	$444	$129	$43
Gain (loss) on transportation and forward commodity derivatives	38	(73)	(3)
Gain (loss) on storage derivatives	86	(16)	14
Inventory LOCOM adjustment, net of estimated current period recoveries	(67)	(1)	(4)
Operating margin	$501	$39	$50

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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 2014, commercial activity increased significantly due to:

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

The 2013 change in commercial activity was primarily due to increased cash optimization opportunities related to constraints of natural gas purchased from producers in the Northeastern U.S. Commercial activity in 2013 was also impacted by 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. Additionally, increased volatility associated with colder weather contributed to the increase in commercial activity.

Change in storage and transportation derivatives A return of significantly higher price volatility in 2014 benefitted Sequent’s portfolio of pipeline transportation and storage capacity assets throughout the country, primarily in the Gulf Coast, Northeast and Midwest markets. Storage derivative gains in 2014 are primarily due to the change in natural gas prices applicable to the locations of our specific storage assets. These increases were partially offset by a $66 million increase in the required LOCOM adjustment to natural gas inventories for the year ended December 31, 2014, net of estimated hedging recoveries.

Gains in our transportation and forward commodity derivative positions in 2014 are primarily the result of narrowing transportation basis spreads. Significantly colder-than-normal weather and higher demand together with natural gas transportation constraints due to growing shale production impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast and the Midwest regions, during 2014. Transportation and forward commodity hedge losses in 2013 were the result of widening transportation basis spreads, and were recovered in 2014 with the physical flow of natural gas and utilization of the contracted transportation capacity.

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 utilizing gas daily or spot prices at the end of the year. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period using forward natural gas prices. This difference in accounting treatment can result in volatility in wholesale services reported results, even though the expected net operating revenue and expected economic value are substantially 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. Largely as a result of moderate weather in the fourth quarter of 2014 leading to significant decreases in natural gas prices, wholesale services recorded a $73 million LOCOM adjustment for the year ended December 31, 2014.

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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 prices 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 protect 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 both 2014 and 2013, we experienced increased price volatility brought on largely by colder weather and supply constraints in the Northeast and Midwest regions, which enabled us to capture value under these market conditions. Commercial activity in 2014 was particularly favorable due to significant natural gas price volatility as compared to prior years, largely the result of significantly colder-than-normal weather primarily in the first quarter. Prior year volatility was significantly lower due to lower daily Henry Hub spot market prices for natural gas in the U.S., robust natural gas supply, mild weather and ample storage.

While market conditions in 2014 experienced more natural gas price volatility, in the near term we anticipate low volatility in certain areas of our portfolio, but expect a continuation of some volatility in the supply-constrained Northeast corridor. Over the longer term, we expect volatility to be low to moderate and locational or transportation spreads to decrease over time as new pipelines are built to reduce the bottleneck in the currently constrained shale areas of the Northeast U.S. To the extent these pipelines are delayed or not built, our expectations are that volatility would increase. While natural gas supply increased during the 2013/2014 Heating Season in the U.S., it was not enough to meet the increased demand, resulting in the lowest storage levels in over a decade. U.S. storage levels have been restored but not to the level of previous years, which could lead to higher natural gas prices under colder-than-normal weather conditions. Additional economic factors may contribute to this environment, including the significant drop in oil and natural gas prices, which could lead to consolidation of natural gas producers and reduced levels of natural gas production. Further, if economic conditions continue to improve, the demand for natural gas may increase, which may cause natural gas prices to rise and drive higher volatility in the natural gas markets on a longer-term basis. We continue to position Sequent's business model with respect to fixed costs and the types of contracts pursued and executed, focusing on opportunities associated with expected new builds of power generation stations, LNG exporters and natural gas utilities and producers.

Sequent's expected natural gas withdrawals from storage and expected offset to hedge losses/gains associated with Sequent's transportation portfolio at December 31, 2014 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, 2014. A portion of Sequent's storage inventory and transportation capacity is economically hedged with futures contracts, which results in realization of substantially fixed net operating revenues, timing notwithstanding.

	Storage withdrawal schedule		
Dollars in millions	Total storage (in Bcf) (WACOG $2.92)	Expected net operating (losses) gains (1)	Physical transportation transactions – expected net operating losses (2)
2015	66	$ (5)	$ (19)
2016 and thereafter	5	2	(19)
Total at December 31, 2014 (3)	71	$ (3)	$ (38)

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

(2) Represents the periods associated with the transportation derivative (gains) losses during which the derivatives will be settled and the physical transportation transactions will occur that offset the derivative (gains) losses recognized.

(3) Includes 5 Bcf in storage with expected operating revenues of $2 million that is currently inaccessible due to operational issues at a third-party storage facility. The owner of this facility is working to resolve these issues and the facility is expected to be operational by mid-2015. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

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For the year ended December 31, 2014, we have recorded $86 million in gains associated with the hedging of our storage position, compared to $16 million in storage hedge losses in 2013. These hedge gains primarily relate to changes in natural gas prices during the fourth quarter of 2014 largely resulting from moderate weather. Sequent's storage withdrawals associated with existing inventory positions 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 (losses) 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, 2014, we have recorded $38 million in gains associated with the hedging of our transportation portfolio as compared to hedge losses of $73 million for the same period last year. Hedge losses in 2013 primarily related to forward transportation and commodity positions for 2014 and were largely offset in 2014 when the expected economic value was realized upon the physical flow of natural gas and the utilization of the contracted transportation capacity.

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."

For a 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 and operation of high-deliverability underground natural gas storage and pipeline assets. While this business can also generate additional revenue during times of peak market demand for natural gas storage services, certain of our storage services are covered under short-, medium- and long-term contracts at fixed market rates. Based on an engineering study and mechanical integrity tests performed in 2014, we identified a lower amount of working gas capacity, further resulting in the true-up of retained fuel at one of our storage facilities, negatively impacting EBIT by $10 million for the year ended December 31, 2014. The decrease in working gas capacity is a result of naturally occurring shrinkage of the storage cavern, and we are developing strategies to recover the decreased working capacity.

In millions	2014		2013	
EBIT - prior year	$(10	)	$10	
Operating margin				
Decrease at Jefferson Island and Central Valley primarily due to lower subscription rates, as well as hedge gains at Central Valley in 2012 that did not occur in 2013	(6	)	(5	)
Decrease at one of our storage facilities related to true-up of retained fuel, partially offset by higher interruptible operating margins largely at Golden Triangle in 2014 due to optimizing the facilities during the significantly colder weather in 2014	(4	)	-	
Decrease in operating margin	(10	)	(5	)
Operating expenses				
Increased maintenance, outside service costs, depreciation expense and other	4		-	
	-		8	

Increase from Central Valley Storage and Cavern 2 at Golden Triangle both beginning commercial service during 2012, and entry into the LNG markets		
Increase in operating expenses	4	8
Increase (decrease) in other income, primarily related to the impairment loss at Sawgrass Storage in December 2013	7	(7)
EBIT - current year	$(17)	$(10)

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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 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.

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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.

We believe the amounts available to us under our long-term debt and credit facilities, as well as through the issuance of debt and equity securities combined with cash provided by operating activities will continue to allow us to meet our needs for working capital, pension and retiree welfare benefits, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years. However, considering our January 2015 maturity of $200 million of senior notes that were repaid with commercial paper, our higher expected capital expenditures related to utility rate base and infrastructure investment and our recently announced pipeline projects, we anticipate issuing additional long-term debt as our financing needs and market conditions warrant.

Our ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which we are unable to control. These factors include, among others, regulatory changes, the price of and demand for natural gas, and operational risks.

Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of debt and equity securities. This strategy includes active management of the percentage of total debt relative to total capitalization, as well as the term and interest rate profile of our debt securities and maintenance of an appropriate mix of debt with fixed and floating interest rates. Our variable debt target is 20% to 45% of total debt. As of December 31, 2014, our variable-rate debt was $1.5 billion, or 31%, of our total debt, compared to $1.4 billion, or 28%, as of December 31, 2013. The increase was due to $120 million of senior notes that converted from fixed-rate to variable-rate during 2014. For more information on our debt, see Note 8 to our consolidated financial statements under Item 8 herein.

In January 2015, we executed $800 million in notional value of 10 year and 30 year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated issuances of senior notes in 2015 and 2016. These debt issuances will be used to reduce our commercial paper for the amount that was borrowed to repay our senior notes that matured in January 2015 and to fund upcoming debt maturities as well as the capital expenditures associated with increased utility investment and construction of our new pipeline projects. We have designated the forward-starting interest rate swaps, which will mature on the debt issuance dates, as cash flow hedges. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" for additional information.

Our objective continues to be maintaining our strong balance sheet and liquidity profile, solid investment grade ratings and our annual dividend growth. Additionally, we will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies, acquisitions and other factors. See Item 1A, "Risk Factors" for additional information on items that could impact our liquidity and capital resource requirements.

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

In millions	Year-end balance outstanding (1)	Daily average balance outstanding (2)	Minimum balance outstanding (2)	Largest balance outstanding (2)
Commercial paper - AGL Capital	$ 590	$ 399	$ -	$ 1,006
Commercial paper - Nicor Gas	585	279	58	614
Senior notes (3)	200	192	-	200
Total short-term debt and current portion of long-term debt	$ 1,375	$ 870	$ 58	$ 1,820

(1) As of December 31, 2014.

(2) For the twelve months ended December 31, 2014. 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.

(3) These senior notes matured in January 2015 and were repaid using commercial paper.

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

Our commercial paper borrowings are supported by the $1.3 billion AGL Credit Facility and $700 million Nicor Gas Credit Facility. The credit facilities can be drawn upon to meet working capital and other general corporate needs; however, the Nicor Gas Credit Facility can only be used for the working capital needs of Nicor Gas. 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. At December 31, 2014 and 2013, we had no outstanding borrowings under either credit facility.

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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 significantly impact our commercial paper borrowings. Based upon our total debt outstanding as of December 31, 2014, and our maximum 70% debt to total capitalization allowed under our financial covenants, we could potentially borrow an additional $700 million of commercial paper under the AGL Credit Facility and an additional $100 million of commercial paper under the Nicor Gas Credit Facility. As a result, based on current natural gas prices and our expected injection plan, 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, 2014. 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, 2014 and consists of medium-term notes: Series A, Series B, and Series C, which we issued under an indenture dated December 1989; senior notes; first mortgage bonds and gas facility revenue bonds.

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

	Issuance date	Amount (in millions)	Term (in years)	Interest rate
Gas facility revenue bonds	(1)	$ 200	10-20	Floating rate
Senior notes (2)	May 2013	$ 500	30	4.4 %

(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.
(2) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $225 million we borrowed to repay senior notes that matured on April 15, 2013.

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

Credit ratings and outlooks are opinions subject to ongoing review by the rating agencies and may periodically change. The rating agencies regularly review our performance 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, 2014, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $38 million to continue conducting business with certain customers. The following table summarizes our credit ratings as of December 31, 2014 and reflects no change from what was reported in our 2013 Form 10-K/A.

	AGL Resources			Nicor Gas		
	S&P	Moody's (1)	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

(1) Credit ratings are for AGL Capital, whose obligations are fully and unconditionally guaranteed by AGL Resources.

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.

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Default Provisions As indicated below, 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. The following table contains our debt-to-capitalization ratios for December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2014	2013	2014	2013
Debt-to-capitalization ratio as calculated from our Consolidated Statements of Financial Position	57 %	58 %	62 %	54 %
Adjustments (1)	(2)	(1)	-	1
Debt-to-capitalization ratio as calculated within our credit facilities	55 %	57 %	62 %	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, 2014 and 2013. 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	2014	2013	2012
Net cash provided by (used in) (1):			
Operating activities	$655	$971	$1,003
Investing activities	(505)	(876)	(786)
Financing activities	(224)	(121)	(155)
Net (decrease) increase in cash and cash equivalents - continuing operations	(51)	(26)	53

Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	-	9
Cash and cash equivalents (including held for sale) at beginning of period	105	131	69
Cash and cash equivalents (including held for sale) at end of period	31	105	131
Less cash and cash equivalents held for sale at end of period	-	24	23
Cash and cash equivalents (excluding held for sale) at end of period	$31	$81	$108

(1) Includes activity for discontinued operations.

Cash Flow from Operating Activities 2014 compared to 2013 Our net cash flow provided by operating activities in 2014 was $655 million, a decrease of $316 million or 33% from 2013. The decrease was primarily related to (i) income taxes, largely driven by the utilization of a prior period net operating loss that reduced the 2013 tax obligation combined with taxes paid in 2014 due to increased earnings and the repatriation of cumulative foreign earnings of Tropical Shipping, (ii) increased cash for inventory and (iii) trade payables, other than energy marketing, due to higher accrued volumes in December 2013 compared to December 2012. These decreases were partially offset by increases primarily related to (i) higher earnings year over year largely attributed to significantly colder-than-normal weather in the current year and increased price volatility that enabled us to capture value in wholesale services and (ii) net energy marketing receivables and payables, due to higher cash received in 2014 from the prior year.

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 (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) income taxes, 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.

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Cash Flow from Investing Activities Our net cash flow used in investing activities in 2014 decreased $371 million or 42% from 2013, primarily as a result of approximately $225 million proceeds we received from the sale of Tropical Shipping during the third quarter of 2014. The decrease was also attributed to the $122 million spending on the acquisition of approximately 500,000 service plans during the first quarter of 2013. Partially offsetting this decrease was greater spending for PP&E expenditures. Our estimated PP&E expenditures for 2015 and our actual PP&E expenditures incurred in 2014, 2013 and 2012 are quantified in the following table.

In millions	Description	2015 (1)	2014	2013	2012
Distribution business	New construction and infrastructure improvements	$408	$475	$421	$371
Regulatory infrastructure programs (2)	Programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth	424	180	226	263
Storage, pipelines and LNG facilities	Underground natural gas storage facilities, pipeline infrastructure and LNG production and transportation	103	15	8	61
Other	Primarily includes information technology and building and leasehold improvements	130	99	76	80
Total		$1,065	$769	$731	$775

(1) Estimated PP&E expenditures.

(2) Includes Investing in Illinois at Nicor Gas, STRIDE at Atlanta Gas Light, SAVE at Virginia Natural Gas and an enhanced infrastructure program at Elizabethtown Gas.

The 2014 increase in PP&E expenditures of $38 million, or 5%, was due to increased spending of $84 million primarily related to new construction and infrastructure improvements at our utilities. This was partially offset by a $46 million net decrease in expenditures for our regulatory infrastructure programs largely due to PRP at Atlanta Gas Light, which ended in 2013, offset by increased spending on our other regulatory infrastructure programs that primarily included $57 million at Atlanta Gas Light for i-VPR, $24 million at Elizabethtown Gas for AIR and $22 million at Nicor Gas for Investing in Illinois.

Our PP&E expenditures were $731 million for the year ended December 31, 2013, compared to $775 million for the same period in 2012.The decrease of $44 million, or 6%, was primarily due to decreased spending of $49 million on our natural gas storage projects consisting of $35 million at Central Valley and $14 million at Golden Triangle. Additionally, capital expenditures decreased $35 million for strategic projects and $16 million for utility infrastructure enhancement projects at Elizabethtown Gas. These decreases were partially offset by increased expenditures of $54 million for regulatory infrastructure programs at Atlanta Gas Light and $9 million for accelerated infrastructure replacement program projects at Virginia Natural Gas.

Our estimated expenditures for 2015 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 Our net cash flow used in financing activities in 2014 increased $103 million, or 85% from 2013 primarily as the result of our $494 million issuance of senior notes in May 2013 and recovery of working capital at wholesale services, partially offset by our $225 million repayment of senior notes in April 2013 and lower commercial paper repayments in 2014 due to higher working capital needs at distribution operations. For more information on our financing activities, see short and long-term debt within Item 7 under the caption "Liquidity and Capital Resources."

Noncontrolling Interest We recorded cash distributions for SouthStar's dividend distributions to Piedmont of $17 million in 2014 and 2013, and $14 million in 2012 as financing activities in our Consolidated Statements of Cash Flows. The primary reason for the increase in the distribution to Piedmont from 2012 to 2013 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 $233 million in 2014, $222 million in 2013 and $203 million in 2012. 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. We also have authorized unrecognized ratemaking amounts, primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs, which are not reflected within our Consolidated Statements of Financial Position. See Note 3 to our consolidated financial statements under Item 8 herein for additional information.

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. In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services. The following table illustrates our expected future contractual obligation payments and commitments and contingencies as of December 31, 2014.

In millions	Total	2015	2016	2017	2018	2019	2020 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$200	$545	$22	$155	$350	$2,434
Short-term debt	1,175	1,175	-	-	-	-	-
Environmental remediation liabilities (2)	414	87	93	55	47	37	95
Total	$5,295	$1,462	$638	$77	$202	$387	$2,529
Unrecorded contractual obligations and commitments (3)(8):							
Pipeline charges, storage capacity and gas supply (4)	$4,303	$805	$457	$280	$234	$222	$2,305
Interest charges (5)	2,762	179	171	147	146	141	1,978
Operating leases (6)	188	33	31	24	17	18	65
Asset management agreements (7)	32	9	10	7	4	2	-
Standby letters of credit, performance/surety bonds (8)	50	49	1	-	-	-	-
Other	8	3	3	1	1	-	-
Total	$7,343	$1,078	$673	$459	$402	$383	$4,348

(1) Excludes the $75 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $5 million interest rate swaps fair value adjustment. Includes the current portion of long-term debt of $200 million, which matured in January 2015.
(2) Includes charges recoverable through base rates or rate rider mechanisms.
(3) In accordance with GAAP, these items are not reflected in our 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 51 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2014, and is valued at $142 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, 2014 and the maturity date of the underlying debt instrument. As of December 31, 2014, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2015.
(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. 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.

Glossary

Pension and welfare 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 welfare costs for which we are responsible 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 $122 million as of December 31, 2014 and $108 million as of December 31, 2013. 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 welfare plans.

In both 2014 and 2013, no contributions were required to our qualified pension plans. Based on the estimated funded status of the AGL Pension plan, we do not expect any required contribution to the plan in 2015. 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

At December 31, 2014, our regulatory assets were $714 million and regulatory liabilities were $1.7 billion. At December 31, 2013, our regulatory assets were $819 million and regulatory liabilities were $1.7 billion.

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 GAAP are permitted to be capitalized or deferred on the balance sheet because it is probable that they can be recovered through rates. The periods in which revenues or expenses are recognized are impacted by regulation. In instances where other GAAP accounting treatment supersedes Accounting Standards Codification 980 - Regulated Operations, we apply the other GAAP accounting treatment. 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 in income for the period in which the discontinuation occurred. A write-off of all our regulatory assets and regulatory liabilities at December 31, 2014 would result in 5% and 15% decreases in total assets and total liabilities, respectively. For more information on our regulated assets and liabilities, see Note 2 and Note 3 to our consolidated financial statements under Item 8 herein.

Accounting for 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 that 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), oil prices 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 2014 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 30% to over 600%, and were not 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 2023 to reflect the recovery of subscription rates, stabilization of earnings and establishment of a reasonable base year of which we estimated the terminal value. In the terminal year, we assumed a long-term earnings growth rate of 2.5%, which is consistent with our 2013 annual goodwill impairment test, and 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 2013 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next nine 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 2014 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 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 step one of the 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, 2014, we estimate that 11% of our future cash flows will be received over the next 10 years, an additional 24% over the following 10 years and 65% in periods thereafter over the remaining useful lives of our storage facilities.

Long-Lived Assets We depreciate or amortize our long-lived and intangible assets over their estimated useful lives. Currently, we have no significant indefinite-lived intangible assets. We assess our long-lived and 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. 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 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 2014; however, our Golden Triangle storage facility within midstream operations currently has less than a 5% cushion of its undiscounted cash flows over its book value. Accordingly, if this facility experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of these long-lived assets.

Our agreement in June 2013 to acquire customer relationship intangible assets within our retail operations segment included a provision for the seller to provide an adjustment to the $32 million purchase price for attrition that exceeds historical levels. In January 2015, we received $5 million from the seller that will be reflected as a reduction to our intangible assets on our Consolidated Statements of Financial Position in 2015 and will reduce the amortization for the same amount over the remaining useful life of 13.5 years.

Derivatives and Hedging Activities

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

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

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

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

We use derivative instruments primarily to reduce the impact to our results of operations due to the risk of changes in the price of natural gas. The fair value of natural gas derivative instruments used to manage our exposure to changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. For the derivatives utilized in retail operations and wholesale services that are not designated as accounting hedges, changes in fair value are reported as gains or losses in our results of operations in the period of change. Retail operations records derivative gains or losses arising from cash flow hedges in OCI and reclassifies them into earnings in the same period that the underlying hedged item is recognized in earnings.

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

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

We have recorded derivative instrument assets of $287 million at December 31, 2014 and $119 million at December 31, 2013. Additionally, we have recorded derivative liabilities of $93 million at December 31, 2014 and $80 million at December 31, 2013. We recorded gains on our Consolidated Statements of Income of $139 million in 2014 and $10 million in 2012 and losses of $97 million in 2013.

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 and Item 1, “Business,” herein.

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.

Glossary

Pension and Welfare Plans

Our pension and welfare 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 welfare plan costs and liabilities and update them when appropriate. The critical actuarial assumptions used to develop the required estimates for our pension and welfare plans include the following key factors:

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

The discount rate is utilized in calculating the actuarial present value of our pension and welfare obligations and our annual net pension and welfare 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 welfare 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, it does not affect that year's annual pension or welfare plan cost; rather, this gain or loss reduces or increases future pension or welfare 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 2014, we recorded net periodic benefit costs of $39 million (pre-capitalization) related to our defined pension and welfare benefit plans. We estimate that in 2015, we will record net periodic pension and welfare benefit costs in the range of $45 million to $49 million (pre-capitalization), a $6 million to $10 million increase compared to 2014. In determining our estimated expenses for 2015, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans		Welfare plans	
Discount rate	4.2	%	4.0	%

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 welfare 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 %	$ (175) / 196	$ (14) / 14

During 2014, our actuary gathered industry specific data in order to assess the appropriateness of the mortality rates for different industries and analyzed our industry group mortality experience. Accordingly, in 2014 we changed the mortality table and mortality improvement scales for the calculation of our benefit obligations as of December 31, 2014. This increased our PBO and accumulated projected benefit obligation (APBO) by $26 million and $10 million, respectively, compared to 2013.

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

With the sale of Tropical Shipping in the third quarter of 2014, we determined that the cumulative foreign earnings of that business would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash.

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 $20 million valuation allowance on $307 million of deferred tax assets ($218 million of long-term and $89 million of current) as of December 31, 2014, reflecting the expectation that a majority of these assets will be realized. Our gross long-term deferred tax liability totaled $1,928 million at December 31, 2014. 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, 2014, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

Accounting Developments

See “Accounting Developments” in Note 2 to our consolidated financial statements under Item 8 herein.

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 instruments and equity that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. We use derivative instruments to manage these risks. Our use of derivative instruments is governed by a risk management policy, approved and monitored by our Risk Management Committee (RMC), which prohibits the use of derivatives for speculative purposes.

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

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 have a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather. For more information, see 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 protect 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 or expansion 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, 2014 and 2013.

	Derivative instruments average values (1) at December 31,	
In millions	2014	2013
Asset	$ 152	$ 107
Liability	101	49

(1) Excludes cash collateral amounts.

In millions	Derivative instruments fair values netted with cash collateral at December 31, 2014	2013
Asset	$ 287	$ 119
Liability	93	80

The following table illustrates the change in the net fair value of our derivative instruments during the 12 months ended December 31, 2014, 2013 and 2012, and provides detail of the net fair value of contracts outstanding as of December 31, 2014, 2013 and 2012.

In millions	2014	2013	2012
Net fair value of derivative instruments outstanding at beginning of period	$(82)	$36	$31
Derivative instruments realized or otherwise settled during period	38	(62)	(61)
Change in net fair value of derivative instruments	105	(56)	66
Net fair value of derivative instruments outstanding at end of period	61	(82)	36
Netting of cash collateral	133	121	69
Cash collateral and net fair value of derivative instruments outstanding at end of period (1)	$194	$39	$105

(1) Net fair value of derivative instruments outstanding includes $3 million premium and associated intrinsic value at December 31, 2014 and 2013, and $4 million at December 31, 2012 associated with weather derivatives.

Glossary

The sources of our net fair value at December 31, 2014 are as follows.

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through 2015	$(28)	$65
Mature 2016 – 2017	7	18
Mature 2018 – 2019	(1)	-
Total derivative instruments (3)	$(22)	$83

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

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

Natural gas markets experienced unprecedented levels of high volatility and prices due to the extended extreme cold weather during the first quarter of 2014, resulting in our VaR to be at elevated levels during the quarter as compared to prior periods. We actively managed and monitored the open positions and exposures that were driving the elevated VaR levels to not only remain in compliance with established policies, but to also mitigate the operational risks of not being able to meet customer needs under these extreme conditions. As conditions moderated at the end of the quarter, our period-end VaR was consistent with historical periods. We actively monitor open commodity positions and the resulting VaR. We also continue to maintain a relatively matched book, where our total buy volume is close to our sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period, SouthStar's portfolio of positions for the 12 months ended December 31, 2014, 2013 and 2012 were less than $0.1 million and Sequent had the following VaRs.

In millions	2014	2013	2012
Period end	$4.7	$4.7	$1.8
12-month average	4.3	2.3	2.0
High	19.7	4.9	4.8
Low	1.8	1.2	1.1

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 $1.5 billion of variable-rate debt outstanding at December 31, 2014, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $15 million on an annualized basis.

We sometimes 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 may also 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 2 and Note 5 to our consolidated financial statements under Item 8 herein.

During the fourth quarter of 2014, $120 million of our senior notes converted from a fixed interest rate to a LIBOR-based variable interest rate. During the first quarter of 2015, we executed $800 million of fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated debt issuances in 2015 and 2016. We have designated the forward-starting interest rate swaps, which will be settled on the debt issuance dates, as cash flow hedges.

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 2014, the four largest Marketers based on customer count accounted for approximately 14% of our consolidated operating margin and 20% 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 in 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, 2014, for agreements with such features, our distribution operations derivative instruments with liability fair values totaled $44 million, for which we had posted $20 million of 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, 2014, our top 20 counterparties represented approximately 55% of the total counterparty exposure of $665 million, excluding $6 million of customer deposits.

As of December 31, 2014, our counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows our third-party natural gas contracts receivable and payable positions as of December 31.

	Gross receivables		Gross payables	
In millions	2014	2013	2014	2013
Netting agreements in place:				
Counterparty is investment grade	$482	$496	$276	$265
Counterparty is non-investment grade	4	-	7	10
Counterparty has no external rating	263	260	494	393
No netting agreements in place:				
Counterparty is investment grade	30	29	-	2
Counterparty has no external rating	-	1	-	1
Amount recorded on Consolidated Statements of Financial Position	$779	$786	$777	$671

We have certain trade and credit contracts that have explicit minimum credit rating requirements. These credit rating requirements typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting business with some of our counterparties. If such collateral were not posted, our ability to continue transacting business with these counterparties would be impaired. If our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements with our counterparties would have totaled $14 million at December 31, 2014, which would not have a material impact on 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, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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 the accompanying Management's Report on Internal Control Over Financial Reporting. 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, Georgia
February 11, 2015

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

Under the supervision and with the participation of our principal executive officer and principal financial officer, management conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2014, using the criteria described in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (the “COSO Framework”).

Based on our evaluation under the COSO Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 11, 2015

/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

	As of December 31,	
In millions	2014	2013
Current assets		
Cash and cash equivalents	$31	$81
Short-term investments	8	49
Receivables		
Energy marketing	779	786
Natural gas	391	385
Unbilled revenues	256	268
Other	150	83
Less allowance for uncollectible accounts	35	29
Total receivables, net	1,541	1,493
Inventories		
Natural gas	694	637
Other	22	21
Total inventories	716	658
Derivative instruments	245	99
Prepaid expenses	223	63
Regulatory assets	83	114
Assets held for sale	-	283
Other	43	55
Total current assets	2,890	2,895
Long-term assets and other deferred debits		
Property, plant and equipment	11,552	10,938
Less accumulated depreciation	2,462	2,295
Property, plant and equipment, net	9,090	8,643
Goodwill	1,827	1,827
Regulatory assets	631	705
Intangible assets	125	145
Long-term investments	105	113
Pension assets	97	117
Derivative instruments	42	20
Other	102	85
Total long-term assets and other deferred debits	12,019	11,655
Total assets	$14,909	$14,550

See Notes to Consolidated Financial Statements.

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

	As of December 31,	
In millions, except share amounts	2014	2013
Current liabilities		
Short-term debt	$1,175	$1,171
Energy marketing trade payables	777	671
Other accounts payable – trade	312	421
Current portion of long-term debt	200	-
Customer deposits and credit balances	125	136
Regulatory liabilities	112	183
Accrued wages and salaries	97	66
Derivative instruments	88	75
Accrued environmental remediation liabilities	87	70
Accrued taxes	79	85
Accrued interest	53	52
Liabilities held for sale	-	40
Other	114	148
Total current liabilities	3,219	3,118
Long-term liabilities and other deferred credits		
Long-term debt	3,602	3,813
Accumulated deferred income taxes	1,724	1,628
Regulatory liabilities	1,601	1,518
Accrued pension and retiree welfare benefits	525	404
Accrued environmental remediation liabilities	327	377
Other	83	79
Total long-term liabilities and other deferred credits	7,862	7,819
Total liabilities and other deferred credits	11,081	10,937
Commitments, guarantees and contingencies (see Note 11)		
Equity		
Common shareholders' equity		
Common stock, $5 par value; 750,000,000 shares authorized; outstanding: 119,647,149 shares at December 31, 2014 and 118,888,876 shares at December 31, 2013	599	595
Additional paid-in capital	2,087	2,054
Retained earnings	1,312	1,063
Accumulated other comprehensive loss	(206)	(136)
Treasury shares, at cost: 216,523 shares at December 31, 2014 and 2013	(8)	(8)
Total common shareholders' equity	3,784	3,568
Noncontrolling interest	44	45
Total equity	3,828	3,613
Total liabilities and equity	$14,909	$14,550

See Notes to Consolidated Financial Statements.

AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Years ended December 31,		
In millions, except per share amounts	2014	2013	2012
Operating revenues (includes revenue taxes of $133 for 2014, $112 for 2013 and $86 for 2012)	$5,385	$4,209	$3,562
Operating expenses			
Cost of goods sold	2,765	2,110	1,583
Operation and maintenance	939	887	816
Depreciation and amortization	380	397	394
Taxes other than income taxes	208	187	159
Nicor merger expenses	-	-	20
Total operating expenses	4,292	3,581	2,972
Gain on disposition of assets	2	11	-
Operating income	1,095	639	590
Other income, net	14	16	24
Interest expense, net	(179)	(170)	(183)
Income before income taxes	930	485	431
Income tax expense	350	177	157
Income from continuing operations	580	308	274
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income	500	313	275
Less net income attributable to the noncontrolling interest	18	18	15
Net income attributable to AGL Resources Inc.	$482	$295	$260
Amounts attributable to AGL Resources Inc.			
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Per common share information			
Basic earnings (loss) per common share			
Continuing operations	$4.73	$2.46	$2.21
Discontinued operations	(0.67)	0.04	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$4.06	$2.50	$2.22
Diluted earnings (loss) per common share			
Continuing operations	$4.71	$2.45	$2.20
Discontinued operations	(0.67)	0.04	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21
Cash dividends declared per common share	$1.96	$1.88	$1.74
Weighted average number of common shares outstanding			
Basic	118.8	117.9	117.0
Diluted	119.2	118.3	117.5

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
In millions	2014	2013	2012
Net income	$500	$313	$275
Other comprehensive income (loss), net of tax			
Retirement benefit plans, net of tax			
Actuarial (loss) gain arising during the period (net of income tax of $48, $46 and $16)	(71)	66	(17)
Prior service cost arising during the period (net of income tax of $1)	-	-	1
Reclassification of actuarial loss to net benefit cost (net of income tax of $6, $10 and $9)	9	15	13
Reclassification of prior service cost to net benefit cost (net of income tax of $1, $2 and $2)	(1)	(3)	(2)
Retirement benefit plans, net	(63)	78	(5)
Cash flow hedges, net of tax			
Net derivative instrument (loss) gain arising during the period (net of income tax of $2, $1 and $-)	(6)	1	(2)
Reclassification of realized derivative (gain) loss to net income (net of income tax of $2, $1 and $3)	(3)	3	6
Cash flow hedges, net	(9)	4	4
Other comprehensive income (loss), net of tax	(72)	82	(1)
Comprehensive income	428	395	274
Less comprehensive income attributable to noncontrolling interest	16	18	15
Comprehensive income attributable to AGL Resources Inc.	$412	$377	$259

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

	AGL Resources Inc. Shareholders							
	Common stock		Additional paid-in	Retained	Accumulated other comprehensive	Treasury	Noncontrolling	
In millions, except per share amounts	Shares	Amount	capital	earnings	loss	shares	interest	Total
As of December 31, 2011	117.0	$586	$ 1,989	$933	$ (217)	$(7)	$ 21	$3,305
Net income	-	-	-	260	-	-	15	275
Other comprehensive loss	-	-	-	-	(1)	-	-	(1)
Dividends on common stock ($1.74 per share)	-	-	-	(203)	-	-	-	(203)
Distributions to noncontrolling interests	-	-	-	-	-	-	(14)	(14)
Stock granted, share-based compensation, net of forfeitures	-	-	(10)	-	-	-	-	(10)
Stock issued, dividend reinvestment plan	0.3	1	9	-	-	-	-	10
Stock issued, share-based compensation, net of forfeitures	0.6	3	19	-	-	(1)	-	21
Stock-based compensation expense, net of tax	-	-	8	-	-	-	-	8
As of December 31, 2012	117.9	$590	$ 2,015	$990	$ (218)	$(8)	$ 22	$3,391
Net income	-	-	-	295	-	-	18	313
Other comprehensive income	-	-	-	-	82	-	-	82
Dividends on common stock ($1.88 per share)	-	-	-	(222)	-	-	-	(222)
Contribution from noncontrolling interest	-	-	-	-	-	-	22	22
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)

Stock granted, share-based compensation, net of forfeitures	-	-	(6)	-	-	-	-	(6)
Stock issued, dividend reinvestment plan	0.3	1	10	-	-	-	-	11
Stock issued, share-based compensation, net of forfeitures	0.7	4	24	-	-	-	-	28
Stock-based compensation expense, net of tax	-	-	11	-	-	-	-	11
As of December 31, 2013	118.9	$595	$ 2,054	$1,063	$ (136)	$(8)	$ 45	$3,613
Net income	-	-	-	482	-	-	18	500
Other comprehensive income	-	-	-	-	(70)	-	(2)	(72)
Dividends on common stock ($1.96 per share)	-	-	-	(233)	-	-	-	(233)
Distributions to noncontrolling interests	-	-	-	-	-	-	(17)	(17)
Stock granted, share-based compensation, net of forfeitures	-	-	(11)	-	-	-	-	(11)
Stock issued, dividend reinvestment plan	0.2	1	11	-	-	-	-	12
Stock issued, share-based compensation, net of forfeitures	0.5	3	19	-	-	-	-	22
Stock-based compensation expense, net of tax	-	-	14	-	-	-	-	14
As of December 31, 2014	119.6	$599	$ 2,087	$1,312	$ (206)	$(8)	$ 44	$3,828

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

In millions	Years ended December 31, 2014	2013	2012
Cash flows from operating activities			
Net income	$500	$313	$275
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	380	397	394
Deferred income taxes	201	(16)	157
Change in derivative instrument assets and liabilities	(155)	66	72
Gain on disposition of assets	(2)	(11)	-
Loss (income) from discontinued operations, net of tax	80	(5)	(1)
Changes in certain assets and liabilities			
Energy marketing receivables and trade payables, net	113	(54)	(44)
Accrued expenses	32	39	(28)
Prepaid and miscellaneous taxes	(244)	103	41
Trade payables, other than energy marketing	(81)	89	49
Accrued/deferred natural gas costs	(67)	2	37
Inventories	(58)	41	43
Receivables, other than energy marketing	(55)	(74)	12
Other, net	21	70	(18)
Net cash flow (used in) provided by operating activities of discontinued operations	(10)	11	14
Net cash flow provided by operating activities	655	971	1,003
Cash flows from investing activities			
Expenditures for property, plant and equipment	(769)	(731)	(775)
Dispositions of assets	230	12	-
Acquisitions of assets	-	(154)	-
Other, net	47	8	(6)
Net cash flow used in investing activities of discontinued operations	(13)	(11)	(5)
Net cash flow used in investing activities	(505)	(876)	(786)
Cash flows from financing activities			
Benefit, dividend reinvestment and stock purchase plan	22	33	21
Net issuances (repayments) of commercial paper	4	(206)	56
Dividends paid on common shares	(233)	(222)	(203)
Distribution to noncontrolling interest	(17)	(17)	(14)
Issuance of senior notes	-	494	-
Contribution from noncontrolling interest	-	22	-
Payment of senior notes	-	(225)	-
Proceeds from termination of interest rate swap	-	-	17
Payment of medium-term notes	-	-	(15)
Other, net	-	-	(17)
Net cash flow used in financing activities	(224)	(121)	(155)
Net (decrease) increase in cash and cash equivalents - continuing operations	(51)	(26)	53

Net (decrease) increase in cash and cash equivalents - discontinued operations	(23)	-	9
Cash and cash equivalents (including held for sale) at beginning of period	105	131	69
Cash and cash equivalents (including held for sale) at end of period	31	105	131
Less cash and cash equivalents held for sale at end of period	-	24	23
Cash and cash equivalents (excluding held for sale) at end of period	$31	$81	$108
Cash paid (received) during the period for			
Interest	$187	$175	$174
Income taxes	422	120	(37)
Non cash financing transaction			
Refinancing of gas facility revenue bonds	$-	$200	$-

See Notes to Consolidated Financial Statements.

Glossary

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, 2014 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 or otherwise controlled subsidiaries and the accounts of our variable interest entity, SouthStar, 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 is probable under the affiliates' rate regulation process.

In November 2014, we filed a 2013 Form 10-K/A to revise our financial statements and other affected disclosures for items related to the recognition of revenues for certain of our regulatory infrastructure programs and the amortization of our intangible assets as filed in our 2013 Form 10-K. Our prior period financial statements reflect the revised amounts reported in our 2013 Form 10-K/A.

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

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

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, $24 million of cash and cash equivalents within our Consolidated Statements of Financial Position held by Tropical Shipping were excluded from cash and cash equivalents and included in assets held for sale. Prior to closing the sale, cash and short-term investments that were held in off-shore accounts were repatriated. See Note 12 and Note 14 for additional information on our income taxes on the cumulative foreign earnings for which no tax liability had previously been recorded.

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements that enable our wholesale services segment to net receivables and payables by counterparty upon settlement. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. While the amounts due from, or owed to, wholesale services' counterparties are settled net, they are recorded on a gross basis in our 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, 2014 and 2013, the collateral that wholesale services would have been required to post if our credit ratings had been downgraded to non-investment grade status would not have had a material impact to our consolidated results of operations, cash flows or financial condition. If such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be negatively impacted.

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. As of December 31, 2014, our top 20 counterparties represented 55%, or $367 million, of our total counterparty exposure and had a weighted average S&P equivalent rating of A-.

Glossary

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, 2014, the Nicor Gas LIFO inventory balance was $141 million. Based on the average cost of gas purchased in December 2014, the estimated replacement cost of Nicor Gas' inventory at December 31, 2014 was $346 million, which exceeded the LIFO cost by $205 million. During 2014, we liquidated 6.8 Bcf of our LIFO-based inventory at an average cost per million cubic feet (Mcf) of $3.98. For gas purchased in 2014, our average cost per Mcf was $1.33 higher than the average LIFO liquidation rate. Applying LIFO cost in valuing the liquidation, as opposed to using the average gas purchase cost, had the effect of decreasing the cost of gas in 2014 by $9 million.

Glossary

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. As indicated in the following LOCOM table, for any declines considered to be other than temporary, we record these pre-tax adjustments to our Consolidated Statements of Income to reduce the weighted average cost of the natural gas inventory to market value.

In millions	2014	2013	2012
Retail operations	$4	$1	$3
Wholesale services (1)	73	8	19
Midstream operations	-	-	1
Total	$77	$9	$23

(1) The increase in 2014 was due to a significant decline in natural gas prices in December 2014.

Additionally, we have $17 million of inventory at wholesale services that is currently inaccessible due to operational issues at a third-party storage facility. The owner of the storage facility is working to resolve these issues. While we expect this inventory to be fully recovered, the timing of withdrawal of this gas may be impacted by the operational issues.

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

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 that would otherwise be charged to expense in the current period are capitalized as regulatory assets when it is probable that such costs 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 and regulatory liabilities are amortized into our Consolidated Statements of Income over the period authorized by the regulatory commissions.

Fair Value Measurements

We have financial and nonfinancial assets and liabilities subject to fair value measurement. The financial assets and liabilities measured and carried at fair value include cash and cash equivalents, and derivative assets and liabilities. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate fair value. Our nonfinancial assets and liabilities include pension and other retirement benefits. 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.

Glossary

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. Our Level 3 assets, liabilities and any applicable transfers are primarily related to our pension and welfare benefit plan assets as described in Note 4 and Note 6. 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 measurement of fair value 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 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 have a corporate weather hedging program that utilizes weather derivatives to reduce the risk of lower operating margins potentially resulting from significantly warmer-than-normal weather in Illinois and is carried at intrinsic value. We will continue to use available methods to mitigate our exposure to weather in Illinois.

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 protect 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 protect 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 substantially 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, 2014 and 2013 is provided in the following table.

In millions	2014	2013
Transportation and distribution	$9,105	$8,371
Storage facilities	1,202	1,170
Other	919	854
Construction work in progress	326	543
Total PP&E, gross	11,552	10,938
Less accumulated depreciation	2,462	2,295
Total PP&E, net	$9,090	$8,643

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

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

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

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

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

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.

	2014		2013		2012	
Atlanta Gas Light (1)	2.3	%	2.6	%	2.6	%
Chattanooga Gas (1)	2.5	%	2.5	%	2.5	%
Elizabethtown Gas (2)	2.5	%	2.4	%	2.4	%
Elkton Gas (2)	2.8	%	2.4	%	2.4	%
Florida City Gas (2)	3.9	%	3.8	%	3.9	%
Nicor Gas (2) (3)	3.1	%	3.1	%	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) In October 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 2014 and 2013 depreciation expense by $51 million and $19 million, respectively.

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

In years	Estimated useful life
Transportation equipment	5 – 10
Storage caverns	40 – 60
Other	up to 40

AFUDC and Capitalized Interest

Atlanta Gas Light, Nicor Gas, Chattanooga Gas and Elizabethtown Gas are authorized by applicable state regulatory agencies or legislatures to capitalize the cost of debt and equity funds as part of the cost of PP&E construction projects in our Consolidated Statements of Financial Position. The capital expenditures of our other three utilities do not qualify for AFUDC treatment. More information on our authorized or actual AFUDC rates is provided in the following table.

	2014		2013		2012	
Atlanta Gas Light	8.10	%	8.10	%	8.10	%
Nicor Gas (1)	0.24	%	0.31	%	0.36	%
Chattanooga Gas	7.41	%	7.41	%	7.41	%
Elizabethtown Gas (1)	0.44	%	0.41	%	0.51	%
AFUDC (in millions) (2)	$7		$18		$8	

(1) Variable rate is determined by FERC method of AFUDC accounting.

(2) Amount recorded in the Consolidated Statements of Income.

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, 2014 and 2013 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.

Glossary

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 2014 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 30% to over 600%, 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 2023 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%, which is consistent with our 2013 annual goodwill impairment test, and 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 2013 annual goodwill impairment test.

The cash flow forecast for the storage and fuels reporting unit assumed earnings growth over the next nine 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 2014 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 amounts of goodwill as of December 31, 2014 and 2013 are provided below. In 2013, our goodwill increased by $51 million for an acquisition in our retail operations segment. For 2013, the goodwill at Tropical Shipping was classified as held for sale. See Note 14 for additional information.

In millions	Distribution operations	Retail operations	Wholesale services	Midstream operations	Other	Consolidated
Goodwill - December 31, 2014 and 2013	$1,640	$173	$-	$14	$-	$ 1,827

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Long-Lived Assets We depreciate or amortize our long-lived assets and other intangible assets over their useful lives. 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. 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 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 2014; however, our Golden Triangle storage facility within midstream operations currently has less than a 5% cushion of its undiscounted cash flows over its book value. Accordingly, if it experiences further natural gas price declines or a prolonged slow recovery, future analyses may result in an impairment of these long-lived assets. We will continue to monitor the storage assets in midstream operations. In 2013, we recorded an $8 million loss related to Sawgrass Storage.

Intangible Assets Our intangible assets within our retail operations segment 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.

		December 31, 2014			December 31, 2013		
In millions	Weighted average amortization period (in years)	Gross	Accumulated amortization	Net	Gross	Accumulated amortization	Net
Customer relationships	13	$130	$ (42)	$88	$130	$ (25)	$105
Trade names	13	45	(8)	37	45	(5)	40
Total		$175	$ (50)	$125	$175	$ (30)	$145

We amortize these intangible assets in a manner in which the economic benefits are consumed utilizing the undiscounted cash flows that were used in the determination of their fair values. Amortization expense was $20 million in 2014, $18 million in 2013 and $13 million in 2012. Amortization expense for the next five years is as follows:

In millions	Amortization Expense
2015	$ 17
2016	15
2017	14
2018	13
2019	11

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 generally 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 defers the change in funded status that would normally be charged or credited 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.

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.

With the sale of Tropical Shipping in the third quarter of 2014, we determined that the cumulative foreign earnings of that business would no longer be indefinitely reinvested offshore. Accordingly, we recognized income tax expense of $60 million in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded, resulting in our repatriation of $86 million in cash. Refer to Note 14 for additional information.

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 upon 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 that allow the opportunity to recover 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, unbilled 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. 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 WNAs have the effect of reducing customer bills when winter weather is colder-than-normal and increasing customer 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 by us to customers, which for some taxes includes a small administrative fee, as operating revenues, and to record the related taxes imposed on us 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 the tax is imposed on the customer. 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 $130 million in 2014, $110 million in 2013 and $85 million in 2012.

Glossary

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, unbilled 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. 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 Revenues from energy and risk management activities are required under authoritative guidance to be netted with the associated costs. Profits from sales between segments are eliminated and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under authoritative guidance related to derivatives and hedging are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses. Gains and losses on derivatives held for energy trading purposes are required to be presented net in revenue.

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

Cost of Goods Sold

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

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

Operating Leases

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

Other Income

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

In millions	2014	2013	2012
Equity investment income	$8	$3	$13
AFUDC - equity	5	12	6
Other, net	1	1	5
Total other income	$14	$16	$24

Earnings Per Common Share

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

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options award programs. The vesting of certain shares of the restricted stock and restricted stock units depends on the satisfaction of defined performance criteria and/or time-based criteria. The future issuance of shares underlying the outstanding stock options depends on whether the market price of the common shares underlying the options exceeds the respective exercise prices of the stock options.

The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented as if performance units currently earned under the plan ultimately vest and as if stock options currently exercisable at prices below the average market prices are exercised.

In millions (except per share amounts)	2014	2013	2012
Income from continuing operations attributable to AGL Resources Inc.	$562	$290	$259
(Loss) income from discontinued operations, net of tax	(80)	5	1
Net income attributable to AGL Resources Inc.	$482	$295	$260
Denominator:			
Basic weighted average number of common shares outstanding (1)	118.8	117.9	117.0
Effect of dilutive securities	0.4	0.4	0.5
Diluted weighted average number of common shares outstanding (2)	119.2	118.3	117.5
Basic earnings per common share			
Continuing operations	$4.73	$2.46	$2.21
Discontinued operations	(0.67)	0.04	0.01
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$4.06	$2.50	$2.22
Diluted earnings per common share (2)			
Continuing operations	$4.71	$2.45	$2.20
Discontinued operations	(0.67)	0.04	0.01
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$4.04	$2.49	$2.21

(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.

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 were eligible to receive contingent cash consideration up to $8 million with a guaranteed minimum receipt of $3 million that was recognized during 2013. The remaining $5 million of contingent cash consideration was to be received from the buyer annually over a five-year earn out period based upon the financial performance of Compass Energy. In the third quarter of 2014, we negotiated with the buyer to settle the future earn-out payments and we received $4 million, resulting in the recognition of a $3 million gain. We have a five-year agreement through April 2018 to supply natural gas to our former customers. As a result of our continued involvement, the sale of Compass Energy did not meet the criteria for treatment as a discontinued operation in 2014. Under the new accounting guidance, which became effective for us on January 1, 2015, the sale of Compass Energy is not considered a strategic shift in operations and would not be reflected as a discontinued operation if we were to terminate our continued involvement in the future.

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.

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. These intangible assets are being amortized over approximately 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 being amortized over 15 years.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures. Our estimates are based on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Our estimates may involve complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. The most significant estimates relate to our rate-regulated subsidiaries, uncollectible accounts and other allowances for contingent losses, goodwill and other intangible assets, retirement plan benefit obligations, derivative and hedging activities and provisions for income taxes. We evaluate our estimates on an ongoing basis and our actual results could differ from our estimates.

Accounting Developments

In April 2014, the FASB issued authoritative guidance related to reporting discontinued operations. The guidance generally raises the threshold for disposals to qualify as discontinued operations and requires new disclosures of both discontinued operations and certain other material disposals that do not meet the definition of a discontinued operation. The guidance was effective for us prospectively beginning January 1, 2015. It had no impact on our accounting for the sale of Tropical Shipping. There was no impact on January 1, 2015, nor is there any reason we would expect this guidance to have a material impact on our consolidated financial statements in the foreseeable future.

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

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

Note 3 – Regulated Operations

Our regulatory assets and liabilities reflected within our Consolidated Statements of Financial Position as of December 31 are summarized in the following table.

In millions	2014	2013
Regulatory assets		
Recoverable ERC	$49	$45
Recoverable pension and retiree welfare benefit costs	12	9
Recoverable seasonal rates	10	10
Deferred natural gas costs	3	1
Other	9	49
Total regulatory assets - current	83	114
Recoverable ERC	326	433
Recoverable pension and retiree welfare benefit costs	110	99
Long-term debt fair value adjustment	74	82
Recoverable regulatory infrastructure program costs	69	55
Other	52	36
Total regulatory assets - long-term	631	705
Total regulatory assets	$714	$819
Regulatory liabilities		
Bad debt over collection	$33	$41
Accrued natural gas costs	27	92
Accumulated removal costs	25	27
Other	27	23
Total regulatory liabilities - current	112	183
Accumulated removal costs	1,520	1,445
Regulatory income tax liability	34	27
Unamortized investment tax credit	22	26
Bad debt over collection	12	17
Other	13	3
Total regulatory liabilities - long-term	1,601	1,518
Total regulatory liabilities	$1,713	$1,701

Base rates are designed to provide the opportunity to recover 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. 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 over collection, natural gas costs 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 approximately 10 years. The regulatory assets related to debt are also not included in rate base, but the costs are recovered over the term of the debt through the authorized rate of return component of base rates.

Unrecognized Ratemaking Amounts The following table illustrates our authorized ratemaking amounts that are not recognized in our Consolidated Statements of Financial Position. These amounts are primarily composed of an allowed equity rate of return on assets associated with certain of our regulatory infrastructure programs. These amounts will be recognized as revenues in our financial statements in the periods they are collected in rates from our customers.

In millions	Atlanta Gas Light	Virginia Natural Gas	Elizabethtown Gas	Total
December 31, 2014	$113	$12	$ 2	$127
December 31, 2013	80	12	1	93

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

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

Our ERC liabilities are estimates of future remediation costs for investigation and cleanup of our current and former operating sites that are contaminated. These estimates are based on conventional engineering estimates and the use of probabilistic models of potential costs when such estimates cannot be made, on an undiscounted basis. These estimates contain various 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 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 $49 million in revenues over the next 12 months, which is reflected as a current regulatory asset. We recovered $51 million in 2014, $24 million in 2013 and $13 million in 2012 from our ERC rate riders. The following table provides more information on the costs related to remediation of our current and former operating sites.

In millions	Number of sites	Probabilistic model	Engineering estimates (1)	Amount recorded	Expected costs over next 12 months	Cost recovery period

		cost estimates (1)				
Illinois (2)	26	$205 - $462	$ 30	$ 230	$ 41	As incurred
New Jersey	6	105 - 177	14	118	16	7 years
Georgia and Florida	13	40 - 81	15	56	21	5 years
North Carolina (3)	1	n/a	10	10	9	No recovery
Total	46	$350 - $720	$ 69	$ 414 (4)	$ 87	

(1) The year-end ERC cost estimates were completed as of November 30, 2014. The liability recorded reflects a reduction of these cost estimates for expenses incurred during December.

(2) Nicor Gas is responsible in whole or in part for 26 MGP sites, of which two sites have been remediated and their use is no longer restricted by the environmental condition of the property. Nicor Gas and Commonwealth Edison Company are parties to an agreement to cooperate in cleaning up residue at 23 of the sites listed. Nicor Gas' allocated share of cleanup costs for these sites is 52%.

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

(4) Decrease of $33 million from December 31, 2013 primarily relates to lower engineering cost estimates for work completed during 2014, partially offset by a scope increase required by the Georgia Environmental Protection Division for a site in Georgia and increases at three Illinois sites due to refinement of the assumptions used in the cost method.

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

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, 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.

		Actual	Total	Amount refunded in		Amount to be refunded in	
In millions	Benchmark	bad debt	refund	2013	2014	2015	2016
2014	$63	$35	$28	$-	$-	$16	$12
2013	63	21	42	-	25	17	-
2012	63	23	40	24	16	-	-

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.

Nicor Gas In 2013, Illinois enacted legislation that allows Nicor Gas to provide more widespread safety and reliability enhancements to its distribution system. The legislation stipulates that rate increases to customer bills as a result of any infrastructure investments shall not exceed an annual average of 4.0% of base rate revenues. In July 2014, the Illinois Commission approved our new regulatory infrastructure program, Investing in Illinois (previously known as Qualified Infrastructure Plant), for which we may implement rates under the program effective in March 2015.

Atlanta Gas Light Our STRIDE program is comprised of the Integrated System Reinforcement Program (i-SRP), the Integrated Customer Growth Program (i-CGP), and the Integrated Vintage Plastic Replacement Program (i-VPR).

The purpose of the i-SRP is to upgrade our distribution system and liquefied natural gas facilities in Georgia, improve our peak-day system reliability and operational flexibility, and create a platform to meet long-term forecasted growth. 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. 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.

A new $260 million, four-year STRIDE program was approved in December 2013, of which $214 million is for i-SRP related projects and $46 million is 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 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 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 increase to $0.96 beginning in January 2015 and to $1.45 beginning in January 2016, which will continue through 2025.

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

Glossary

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

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

Additionally, in August 2013, we received approval from the New Jersey BPU for an extension of the accelerated infrastructure replacement program, which 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 WACC of 6.65%, of which 4.27% will be within an unrecognized ratemaking amounts and will be recognized in future periods when recovered through rates. Unlike the previous program, there will be no adjustment to base rates for the investments under the extended program until Elizabethtown Gas files its next rate case. We agreed to file a general rate case by September 2016.

In September 2013, Elizabethtown Gas filed for a Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program designed to improve our distribution system's resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas is investing $15 million in infrastructure and related facilities and communication planning over a one year period that began in January 2014. In July 2014, the New Jersey BPU approved a modified ENDURE plan that allows for Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program.

Virginia Natural Gas In 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. The second year performance rate update was approved by the Virginia Commission in July 2014 and became effective as of August 2014.

Energy Smart Plan In May 2014, the Illinois Commission approved Nicor Gas' Energy Smart Plan, which outlines energy efficiency program offerings and therm reduction goals with spending of $93 million over a three-year period that began in June 2014. Nicor Gas' first energy efficiency program ended in May 2014.

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 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.

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Note 4 - Fair Value Measurements

Retirement benefit plans assets

The assets 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 allocated approximately 71% equity and 29% fixed income at December 31, 2014 and 74% equity and 26% fixed income at December 31, 2013 compared to our targets of 70% to 95% equity, 5% to 20% fixed income, and up to 10% cash for both periods. 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, 2014									
	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	$ 4	$ 1	$ -	$ 5	1 %	$ 1	$ -	$ -	$ 1	1 %
Equity securities:										
U.S. large cap (2)	$ 95	$ 203	$ -	$ 298	33 %	$ -	$ 51	$ -	$ 51	57 %
U.S. small cap (2)	76	24	-	100	11 %	-	-	-	-	- %
International companies (3)	-	123	-	123	13 %	-	16	-	16	18 %
Emerging markets (4)	-	31	-	31	3 %	-	-	-	-	- %
Total equity securities	$ 171	$ 381	$ -	$ 552	60 %	$ -	$ 67	$ -	$ 67	75 %
Fixed income securities:										
Corporate bonds (5)	$ -	$ 233	$ -	$ 233	25 %	$ -	$ 22	$ -	$ 22	24 %
Other (or gov't/muni bonds)	-	33	-	33	4 %	-	-	-	-	- %
Total fixed income securities	$ -	$ 266	$ -	$ 266	29 %	$ -	$ 22	$ -	$ 22	24 %
Other types of investments:										
Global hedged equity (6)	$ -	$ -	$ 29	$ 29	3 %	$ -	$ -	$ -	$ -	- %
Absolute return (7)	-	-	42	42	5 %	-	-	-	-	- %
Private capital (8)	-	-	20	20	2 %	-	-	-	-	- %
	$ -	$ -	$ 91	$ 91	10 %	$ -	$ -	$ -	$ -	- %

Total other investments										
Total assets at fair value	$ 175	$ 648	$ 91	$ 914	100 %	$ 1	$ 89	$ -	$ 90	100 %
% of fair value hierarchy	19 %	71 %	10 %	100 %		1 %	99 %	- %	100 %	

	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 %	-	-	-	-	- %
Total equity securities	$165	$407	$-	$572	63 %	$-	$66	$-	$66	79 %
Fixed income securities:										
Corporate bonds (5)	$-	$207	$-	$207	23 %	$-	$17	$-	$17	20 %
Other (or gov't/muni bonds)	-	29	-	29	3 %	-	-	-	-	- %
Total fixed income securities	$-	$236	$-	$236	26 %	$-	$17	$-	$17	20 %
Other types of investments:										
Global hedged equity (6)	$-	$-	$43	$43	5 %	$-	$-	$-	$-	- %
Absolute return (7)	-	-	39	39	4 %	-	-	-	-	- %
Private capital (8)	-	-	22	22	2 %	-	-	-	-	- %
Total other investments	$-	$-	$104	$104	11 %	$-	$-	$-	$-	- %
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 %	

(1) Includes $9 million at December 31, 2014 and December 31, 2013 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.

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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, 2012	$38	$36	$23	$97
Actual return on plan assets	5	3	4	12
Sales	-	-	(5)	(5)
Balance at December 31, 2013	$43	$39	$22	$104
Actual return on plan assets	1	3	2	6
Sales	(15)	-	(4)	(19)
Balance at December 31, 2014	$29	$42	$20	$91

(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 December 31.

	2014		2013	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities
Natural gas derivatives				
Quoted prices in active markets (Level 1)	$58	$(80)	$6	$(79)
Significant other observable inputs (Level 2)	174	(94)	67	(79)
Netting of cash collateral	52	81	43	78
Total carrying value (2) (3)	$284	$(93)	$116	$(80)

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

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

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

Debt

Our long-term debt is recorded at amortized cost, with the exception of Nicor Gas' first mortgage bonds, which are recorded at their acquisition-date fair value. We amortize the fair value adjustment of Nicor Gas' first mortgage bonds over the lives of the bonds. The following table presents the carrying amount and fair value of our long-term debt as of December 31.

In millions	2014	2013
Long-term debt carrying amount	$3,802	$3,813
Long-term debt fair value (1)	4,231	3,956

(1) Fair value determined using Level 2 inputs.

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Note 5 - 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 our risk management activities and enforcing 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 when deemed appropriate:

- 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, 2014 and 2013, for agreements with such features, derivative instruments with liability fair values totaled $93 million and $80 million, respectively, for which we had posted no collateral to our counterparties. The maximum collateral that could be required with these features is $14 million. For more information, see "Energy Marketing Receivables and Payables" in Note 2, which also have credit risk-related contingent features. Our derivative instrument activities are included within operating cash flows as an increase (decrease) to net income of $(155) million, $66 million and $72 million for the periods ended December 31, 2014, 2013 and 2012, respectively.

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 Statements
Cash flow hedge	Derivative carried at fair value	Ineffective portion of the gain or loss realized and unrealized 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 realized and unrealized on the derivative instrument is reclassified out of accumulated OCI (loss) and into earnings when the hedged transaction affects earnings
Fair value hedge	Derivative carried at fair value Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	Gains or losses realized and unrealized on the derivative instrument and the hedged item are recognized in earnings. As a result, to the extent the hedge is effective, the gains or losses will offset and there is no impact on earnings. Any hedge ineffectiveness will impact earnings
Not designated as hedges	Derivative carried at fair value	Gains or losses realized and unrealized 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 realized and unrealized 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. As of December 31, we had a net long natural gas contracts position outstanding in the following quantities:

In Bcf (1)	2014 (2)	2013
Cash flow hedges	9	6
Not designated as hedges	75	183
Total volumes	84	189
Short position – cash flow hedges	(4)	(6)
Short position – not designated as hedges	(2,828)	(2,616)
Long position – cash flow hedges	16	12
Long position – not designated as hedges	2,900	2,799
Net long position	84	189

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

(2) Approximately 100% of these contracts have durations of two years or less and less than 1% expire between two and five years.

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Derivative Instruments in our Consolidated Statements of Financial Position

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

In millions	2014	2013
Nicor Gas	$10	$4
Elizabethtown Gas	2	(6)

The following table presents the fair values and Consolidated Statements of Financial Position classifications of our derivative instruments as of December 31:

		2014		2013	
In millions	Classification	Assets	Liabilities	Assets	Liabilities
Designated as cash flow or fair value hedges					
Natural gas contracts	Current	$6	$(11)	$3	$(1)
Natural gas contracts	Long-term	-	(1)	-	-
Total designated as cash flow or fair value hedges		$6	$(12)	$3	$(1)
Not designated as hedges					
Natural gas contracts	Current	$1,061	$(1,020)	$691	$(761)
Natural gas contracts	Long-term	145	(119)	206	(220)
Total not designated as hedges		$1,206	$(1,139)	$897	$(981)
Gross amount of recognized assets and liabilities (1) (2)		1,212	(1,151)	900	(982)
Gross amounts offset in our Consolidated Statements of Financial Position (2)		(925)	1,058	(781)	902
Net amounts of assets and liabilities presented in our Consolidated Statements of Financial Position (3)		$287	$(93)	$119	$(80)

(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 $133 million as of December 31, 2014 and $121 million as of December 31, 2013. Cash collateral is included in the "Gross amounts offset in our Consolidated Statements of Financial Position" line of this table.

(3) At December 31, 2014 and 2013, 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.

In millions	2014	2013	2012
Designated as cash flow or fair value hedges			
	$4	$(1)	$(5)

Natural gas contracts – net gain (loss) reclassified from OCI into cost of goods sold			
Natural gas contracts – net gain reclassified from OCI into operation and maintenance expense	1	-	-
Interest rate swaps – net loss reclassified from OCI into interest expense	-	(3)	(4)
Income tax (expense)/benefit	(2)	1	3
Total designated as cash flow or fair value hedges, net of tax	$3	$(3)	$(6)
Not designated as hedges (1)			
Natural gas contracts - net gain (loss) recorded in operating revenues	$149	$(90)	$34
Natural gas contracts - net gain (loss) recorded in cost of goods sold (2)	(7)	2	(4)
Income tax (expense)/benefit	(54)	34	(11)
Total not designated as hedges, net of tax	$88	$(54)	$19
Total gains (losses) on derivative instruments, net of tax	$91	$(57)	$13

(1) Associated with the fair value of derivative instruments held at December 31, 2014, 2013 and 2012.

(2) Excludes losses recorded in cost of goods sold associated with weather derivatives of $7 million, $5 million and $14 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Any amounts recognized in operating income related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur were immaterial for the years ended December 31, 2014, 2013 and 2012. 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 are $7 million. These deferred gains are related to natural gas derivative contracts associated with retail operations' and Nicor Gas' system use. The expected gains are based upon the fair values of these financial instruments at December 31, 2014. The effective portion of gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in OCI during the periods is presented on our Consolidated Statements of Income. See Note 9 for these amounts.

Note 6 - Employee Benefit Plans

Investment Policies, Strategies and 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 welfare 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.

In developing our allocation policy for the pension and welfare plan assets we examined projections of asset returns and volatility over a long-term horizon. In connection with this analysis, we evaluated the risk and return tradeoffs of alternative asset classes and asset mixes given long-term historical relationships as well as prospective capital market returns. We also conducted an asset-liability study to match projected asset growth with projected liability growth to determine whether there is sufficient liquidity for projected benefit payments. We developed our asset mix guidelines by incorporating the results of these analyses with an assessment of our risk posture, and taking into account industry practices. We periodically evaluate our investment strategy to ensure that plan assets are sufficient to meet the benefit obligations of the plans. As part of the ongoing evaluation, we may make changes to our targeted asset allocations and investment strategy.

Our investment strategy is designed to meet the following objectives:

- Generate investment returns that, in combination with our funding contributions, provide adequate funding to meet all current and future benefit obligations of the plans.
- Provide investment results that meet or exceed the assumed long-term rate of return, while maintaining the funded status of the plans at acceptable levels.
- Improve funded status over time.
- Decrease contribution and expense volatility as funded status improves.

To achieve these investment objectives, our investment strategy is divided into two primary portfolios of return seeking and liability hedging assets. Return seeking assets are intended to provide investment returns in excess of liability growth and reduce deficits in the funded status of the plans, while liability hedging assets are intended to reflect the sensitivity of the liabilities to changes in discount rates.

See Note 4 for a detailed listing of the investment types, amounts and percentages allocated to the plans. 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. Effective January 1, 2013, the AGL Plan was frozen with respect to participation for 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 reflects the most recent collective bargained agreement terms with regards to the 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 NUI 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 – the 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. Effective March 18, 2014, the Nicor Welfare Plan was closed to participation for all Nicor employees hired on or after that date.

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. Effective March 18, 2014, the life insurance coverage is not available to new employees hired on or after that date. 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 cost limits, there is no impact on our 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.

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 2014 and 2013. The APBO associated with this plan was $2 million at December 31, 2014 and $2 million at December 31, 2013.

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.

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

	Pension plans			Welfare plans		
Dollars in millions	2014	2013	2012	2014	2013	2012
Service cost	$24	$29	$28	$2	$3	$4
Interest cost	47	43	44	15	14	16
Expected return on plan assets	(65)	(62)	(64)	(7)	(6)	(5)
Net amortization of prior service cost	(2)	(2)	(2)	(3)	(5)	(3)
Recognized actuarial loss	22	35	34	6	8	9
Net periodic benefit cost	$26	$43	$40	$13	$14	$21
Assumptions used to determine benefit costs						
Discount rate (1)	5.0%	4.2%	4.6%	4.7%	4.0%	4.5%
Expected return on plan assets (1)	7.8%	7.8%	8.4%	7.8%	7.8%	8.5%
Rate of compensation increase (1)	3.7%	3.7%	3.7%	3.7%	3.8%	3.8%
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 pension bands for the former Nicor Plan have been updated to reflect the new negotiated rates for 2015 and 2016, of 2.0% and 0%, respectively, as indicated in the union agreement dated March 2014.

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

	Pension plans		Welfare plans	
Dollars in millions	2014	2013	2014	2013
Change in plan assets				
Fair value of plan assets, January 1,	$907	$837	$93	$77
Actual return on plan assets	68	134	5	16
Employee contributions	-	-	2	3
Employer contributions	1	1	17	19
Benefits paid	(70)	(65)	(19)	(23)
Medicare Part D reimbursements	-	-	1	1
Fair value of plan assets, December 31,	$906	$907	$99	$93
Change in benefit obligation				
Benefit obligation, January 1,	$960	$1,046	$326	$354
Service cost	24	29	2	3
Interest cost	47	43	15	14
Actuarial loss (gain)	137	(93)	8	(26)
Medicare Part D reimbursements	-	-	1	1
Benefits paid	(70)	(65)	(19)	(23)
Employee contributions	-	-	1	3
Benefit obligation, December 31,	$1,098	$960	$334	$326
Funded status at end of year	$(192)	$(53)	$(235)	$(233)

Amounts recognized in the Consolidated Statements of Financial Position consist of				
Long-term asset (2)	$97	$117	$-	$-
Current liability	(2)	(2)	-	-
Long-term liability	(287)	(168)	(235)	(233)
Net liability at December 31,	$(192)	$(53)	$(235)	$(233)
Accumulated benefit obligation (1)	$1,027	$902	n/a	n/a
Assumptions used to determine benefit obligations				
Discount rate	4.2%	5.0%	4.0%	4.7%
Rate of compensation increase	3.7%	3.7%	3.7%	3.7%
Pension band increase (3)	2.0%	2.0%	n/a	n/a

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

(2) As a result of historically having multiple plans, a portion of our obligation is in an asset position.

(3) 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:

	2014	2013
Health care cost trend rate assumed for next year	8.1%	8.4%
Ultimate rate to which the cost trend rate is assumed to decline	4.5%	4.5%
Year that reaches ultimate trend rate	2030	2030

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates for the AGL Welfare Plan would have the following effects on our benefit obligation and there was no effect on our service and interest cost.

In millions	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 the Plan's periodic benefit cost or accumulated benefit obligation.

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, 2014 and 2013:

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
December 31, 2014						
Prior service credit	$-	$(18)	$(6)	$-	$(6)	$(18)
Net loss	76	57	307	36	383	93
Total	$76	$39	$301	$36	$377	$75
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

The 2015 estimated amortizations out of regulatory assets or accumulated OCI for these plans are set forth in the following table.

	Net regulatory assets		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	9	3	20	2	29	5

We recorded regulatory assets for anticipated future cost recoveries of $122 million and $108 million as of December 31, 2014 and 2013, respectively.

The following table presents the gross benefit payments expected for the years ended December 31, 2015 through 2024 for our pension and welfare plans. There will be benefit payments under these plans beyond 2024.

In millions	Pension plans	Welfare plans
2015	$61	$19
2016	64	20

2017	67	20
2018	70	21
2019	72	22
2020-2024	374	115

Contributions

Our employees generally do not contribute to our pension and welfare 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 2014 and 2013, we had no required contributions to the merged AGL Plan.

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 $17 million in 2014, $14 million in 2013 and $12 million in 2012.

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, 2014, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 587,292 shares. Under the Long-Term Incentive Plan (1999) as of December 31, 2014, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 436,400 shares. The maximum number of shares available for future issuance under the Omnibus Performance Incentive Plan is 3,962,335 shares, which includes 1,551,040 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 and performance 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	2014	2013	2012
Compensation costs (1)	$24	$22	$9
Income tax benefits (1)	1	1	1
Excess tax benefits (2)	-	-	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.

Glossary

As of December 31, 2014 and 2013, we had no unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2014 and 2013 were $9 million and $21 million, respectively, and the income tax benefit from stock option exercises was immaterial for both years. 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, 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		
Granted	-	-		
Exercised	(617,358)	35.37		
Forfeited	(12,500)	38.36		
Outstanding - December 31, 2013 (1)	898,732	$36.55	3.0	$10
Granted	-	-	-	
Exercised	(267,182)	36.84	1.7	
Forfeited	(4,000)	39.71	2.7	
Outstanding - December 31, 2014 (1) (2)	627,550	$36.41	2.2	$11

(1) All options outstanding at December 31, 2014, 2013 and 2012 were exercisable.

(2) The range of exercise prices for the options outstanding at December 31, 2014 was $31.09 to $43.54.

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 2014, 2013 and 2012. 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 2014, we granted 44,272 restricted stock units (including dividends) to certain employees, all of which were outstanding as of December 31, 2014. These restricted stock units had a performance measurement period that ended December 31, 2014. 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 2015 and are subject to a three year service condition.

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. In 2012, 2013 and 2014, 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 2014, 2013 and 2012 grants are as follows:

In millions	Measurement period end date	Fair value accrued at December 31, 2014	Maximum aggregate payout
Granted in 2012	December 31, 2014 (1)	$ 8	$ 20
Granted in 2013	December 31, 2015	7	21
Granted in 2014	December 31, 2016	4	24

(1) The actual liability is $8 million, and the maximum amount that could have been paid was $20 million.

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. Prior to vesting, 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 2014, we issued 21,903 shares with a weighted average fair value of $52.97 to our non-employee directors.

Restricted Stock Awards - Employees The following table summarizes the restricted stock awards activity for our employees during the last three 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		$ 39.44
Issued	175,935		42.41
Forfeited	(33,352)		40.64
Vested	(204,421)		38.71
Outstanding - December 31, 2013 (1)	441,253	1.8	$ 40.82
Issued	262,235	4.4	47.03
Forfeited	(14,895)	2.4	43.41
Vested	(225,683)	-	42.31
Outstanding - December 31, 2014 (1)	462,910	1.8	$ 43.54

(1) Subject to restriction.

Employee Stock Purchase Plan (ESPP)

We have a nonqualified, broad based ESPP for all eligible employees. As of December 31, 2014, there were 422,564 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.

	2014	2013	2012
Shares purchased on the open market	100,199	97,734	103,589
Average per-share purchase price	$51.60	$42.96	$38.96
Total purchase price discount	$739,598	$628,358	$591,855

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, 2014			December 31, 2013		
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)	2015	0.3	%	$ 590	0.4	%	$ 857
Commercial paper - Nicor Gas (2)	2015	0.2		585	0.3		314
Total short-term debt		0.3	%	$ 1,175	0.4	%	$ 1,171
Current portion of long-term debt	2015	5.0	%	$ 200	-	%	$ -
Long-term debt - excluding current portion							
Senior notes	2016-2043	5.0	%	$ 2,625	5.0	%	$ 2,825
First mortgage bonds	2016-2038	5.6		500	5.6		500
Gas facility revenue bonds	2022-2033	0.9		200	1.0		200
Medium-term notes	2017-2027	7.8		181	7.8		181
Total principal long-term debt		4.9	%	$ 3,506	4.9	%	$ 3,706
Fair value adjustment of long-term debt (3)	2016-2038	n/a		80	n/a		91
Unamortized debt premium, net	n/a	n/a		16	n/a		16
Total non-principal long-term debt		n/a		96	n/a		107
Total long-term debt				$ 3,602			$ 3,813
Total debt				$ 4,977			$ 4,984

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the 12 months ended December 31, 2014 and 2013.

(2) As of December 31, 2014, the effective interest rates on our commercial paper borrowings were 0.5% for AGL Capital and 0.4% for Nicor Gas.

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

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Short-term Debt

Our short-term debt at December 31, 2014 and 2013 was comprised 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 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 2014, our commercial paper maturities ranged from 1 to 108 days, and at December 31, 2014, remaining terms to maturity ranged from 2 to 70 days. During 2014, total borrowings and repayments netted to a borrowing of $4 million. For commercial paper issuances with original maturities over three months, borrowings and repayments were $50 million and $195 million, respectively. During 2014, we utilized a portion of the approximately $225 million in proceeds and distributions from the sale of Tropical Shipping to reduce our commercial paper borrowings.

Credit Facilities At December 31, 2014 and 2013, there were no outstanding borrowings under either the AGL Capital or Nicor Gas credit facilities. In 2013, 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 The current portion of our long-term debt at December 31, 2014 is composed of the portion of our long-term debt due within the next 12 months.

Long-term Debt

Our long-term debt at December 31, 2014 and 2013 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 and gas facility revenue bonds. 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 2019. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	Amount (in millions)
2015	$ 200
2016	545
2017	22
2018	155
2019	350
Thereafter	2,434

Total	$	3,706

Senior Notes There were no senior note issuances in 2014; however, during the fourth quarter of 2014, $120 million of senior notes that were issued to help fund the Nicor merger converted from a 1.9% fixed rate to a LIBOR-based floating rate. In 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.

On January 23, 2015, we executed $800 million in notional value of 10 year and 30 year fixed-rate forward-starting interest rate swaps to hedge potential interest rate volatility prior to anticipated issuances of senior notes during 2015 and 2016. These debt issuances will be used to reduce our commercial paper for the amount that was borrowed to repay our senior notes that matured in January 2015 and to fund upcoming debt maturities as well as capital expenditures associated with increased utility investment and construction of our new pipeline projects. We have designated the forward-starting interest rate swaps, which will be settled on the debt issuance dates, as cash flow hedges.

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 and Brevard County, Florida under which a series of gas facility revenue bonds has been issued. These 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, which 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. 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 as of December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2014	2013	2014	2013
Debt-to-capitalization ratio	55 %	57 %	62 %	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 the following:

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

We have no triggering events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other triggering events. We were in compliance with all existing debt provisions and covenants, both financial and non-financial, as of December 31, 2014 and 2013.

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 2014 or 2013.

Preferred Securities

At December 31, 2014 and 2013, 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.

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.

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Accumulated Other Comprehensive Loss

Our share of comprehensive income includes net income plus OCI (loss), which includes changes in fair value of certain derivatives designated as cash flow hedges, certain changes in pension and welfare 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 OCI (loss) amounts are aggregated within accumulated other comprehensive loss on our Consolidated Statement of Financial Position. The following table provides changes in the components of our accumulated other comprehensive loss balances net of the related income tax effects.

In millions (1)	Cash flow hedges	Retirement benefit plans	Total
Balance as of December 31, 2011	$(7)	$(210)	$(217)
Other comprehensive income (loss)	4	(5)	(1)
Balance 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
Balance as of December 31, 2013	1	(137)	(136)
Other comprehensive loss, before reclassifications	(6)	(71)	(77)
Amounts reclassified from accumulated other comprehensive loss	(1)	8	7
Balance as of December 31, 2014	$(6)	$(200)	$(206)

(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 years ended December 31, 2014 and 2013 and the ultimate unfavorable impact on net income.

In millions (1)	December 31, 2014	2013
Cash flow hedges		
Cost of goods sold (natural gas contracts)	$4	$(1)
Operation and maintenance expense (natural gas contracts)	1	-
Interest expense (interest rate contracts)	-	(3)
Total before income tax	5	(4)
Income tax (expense)/benefit	(2)	1
Cash flow hedges net of income tax	3	(3)
Less noncontrolling interest	2	-
Total cash flow hedges net of income tax	1	(3)
Retirement benefit plans		
Operation and maintenance expense (actuarial losses)(2)	(15)	(25)
Operation and maintenance expense (prior service credits) (2)	2	5
Total before income tax	(13)	(20)
Income tax benefit	5	8
Total retirement benefit plans	(8)	(12)
Total reclassification	$(7)	$(15)

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

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

Note 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 our only VIE for which we are the primary beneficiary. This requires us to consolidate its assets, liabilities and Statements of Income. Our conclusion that SouthStar is a VIE resulted from our equal voting rights with Piedmont not being proportional to our economic obligation to absorb 85% of losses or residual returns from the joint venture. We account for our ownership of SouthStar in accordance with authoritative accounting guidance, which is described within Note 2.

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

Operations

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

- meter reading for SouthStar's customers in Illinois and Georgia
- maintenance and expansion of the natural gas infrastructure in Illinois and Georgia
- assignment of 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, legal, human resources, 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 that we have provided to SouthStar's counterparties and natural gas suppliers. We have provided no financial or other support that was not previously contractually required. With the exception of our corporate guarantees 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 $7 million for 2014, $3 million for 2013 and $1 million for 2012. Cash flows used in our financing activities include SouthStar's distribution to Piedmont for its portion of SouthStar's annual earnings from the previous year. Generally, this distribution occurs in the first quarter of each fiscal year. For the years ended December 31, 2014, 2013 and 2012, SouthStar distributed $17 million, $17 million and $14 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 December 31, which are consolidated within our Consolidated Statements of Financial Position.

	2014			2013		
In millions	Consolidated	SouthStar (1)	% (2)	Consolidated	SouthStar (1)	% (2)
Current assets	$ 2,890	$ 238	8 %	$ 2,895	$ 264	9 %
Goodwill and other intangible assets	1,952	125	6	1,972	133	7
Long-term assets and other deferred debits	10,067	17	-	9,683	13	-
Total assets	$ 14,909	$ 380	3 %	$ 14,550	$ 410	3 %
Current liabilities	$ 3,219	$ 71	2 %	$ 3,118	$ 95	3 %
Long-term liabilities and other deferred credits	7,862	-	-	7,819	-	-
Total liabilities	11,081	71	1	10,937	95	1
Equity	3,828	309	8	3,613	315	9
Total liabilities and equity	$ 14,909	$ 380	3 %	$ 14,550	$ 410	3 %

(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.

Glossary

The following table provides information on SouthStar's operating revenues and operating expenses for the years ended December 31, which are consolidated within our Consolidated Statements of Income.

In millions	2014	2013
Operating revenues	$866	$687
Operating expenses		
Cost of goods sold	645	491
Operation and maintenance	87	72
Depreciation and amortization	11	7
Taxes other than income taxes	1	1
Total operating expenses	744	571
Operating income	$122	$116

Equity Method Investments

Triton We have an investment in Triton, a cargo container leasing company, which is included within our "other" non-reportable segment. 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, 2014, we had invested in seven tranches established by Triton.

Horizon Pipeline We own a 50% interest in a joint venture with Natural Gas Pipeline Company of America that is regulated by the FERC and is included within our midstream operations segment. 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 for the development of an underground natural gas storage facility in Louisiana with 30 Bcf of working gas capacity and is included within our midstream operations segment. 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	2014	2013
Triton	$62	$70
Horizon Pipeline	14	15
Other (1)	4	1
Total	$80	$86

(1) Includes our current investment in PennEast Pipeline of $1 million and Atlantic Coast pipeline of $2 million as of December 31, 2014.

Income from our equity method investments is classified as other income in our Consolidated Statements of Income. The following table provides the income from our equity method investments for the years ended December 31. 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 2014 and 2013, we received distributions of $17 million from our equity investees.

In millions	2014	2013	2012
Triton	$6	$9	$11
Horizon Pipeline	2	2	2
Other	-	(8)	-
Total	$8	$3	$13

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

PennEast Pipeline On August 11, 2014, we entered into a joint venture in which we hold a 20% ownership interest to develop and operate a 108-mile natural gas pipeline between New Jersey and Pennsylvania with initial transportation capacity of 1 Bcf per day, which may be expanded to 1.2 Bcf per day. Subject to FERC approval, construction is expected to begin in the first quarter of 2017 with a targeted completion date in the fourth quarter of 2017.

Atlantic Coast Pipeline On September 2, 2014, we entered into a joint venture in which we hold a 5% ownership interest to develop and operate a 550-mile natural gas pipeline in North Carolina, Virginia, and West Virginia with initial transportation capacity of 1.5 Bcf per day, which may be expanded to 2.0 Bcf per day. Subject to FERC approval, construction is expected to begin in the second half of 2016 with a targeted completion date in the second half of 2018.

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. In 2014, we entered into several unconditional purchase obligations in the ordinary course of business. These include capacity and supply agreements related to the Dalton Pipeline, PennEast Pipeline, Atlantic Coast Pipeline and wholesale services, which are reflected in the table below. The following table illustrates our expected future contractual payments under our obligations and other commitments as of December 31, 2014.

In millions	Total	2015	2016	2017	2018	2019	2020 & thereafter
Recorded contractual obligations:							
Long-term debt (1)	$3,706	$200	$545	$22	$155	$350	$2,434
Short-term debt	1,175	1,175	-	-	-	-	-
Environmental remediation liabilities (2)	414	87	93	55	47	37	95
Total	$5,295	$1,462	$638	$77	$202	$387	$2,529
Unrecorded contractual obligations and commitments (3) (8):							
Pipeline charges, storage capacity and gas supply (4)	$4,303	$805	$457	$280	$234	$222	$2,305
Interest charges (5)	2,762	179	171	147	146	141	1,978
Operating leases (6)	188	33	31	24	17	18	65
Asset management agreements (7)	32	9	10	7	4	2	-
Standby letters of credit, performance/surety bonds (8)	50	49	1	-	-	-	-
Other	8	3	3	1	1	-	-
Total	$7,343	$1,078	$673	$459	$402	$383	$4,348

(1) Excludes the $75 million step up to fair value of first mortgage bonds, $16 million unamortized debt premium and $5 million interest rate swaps fair value adjustment. Includes our current portion of long-term debt of $200 million, which matured in January 2015.

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

(3) In accordance with GAAP, these items are not reflected in our 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 51 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2014, and is valued at $142 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, 2014 and the maturity date of the underlying debt instrument. As of December 31, 2014, we have $53 million of accrued interest on our Consolidated Statements of Financial Position that will be paid in 2015.

(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.

Contingencies and Guarantees

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

Financial guarantees AGL Equipment Leasing Inc. (AEL), 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 was not impacted by the 2014 sale of Tropical Shipping and continues for the life of the Triton partnerships. Any payment is effectively limited to the net assets of AEL, which were less than $1 million at December 31, 2014. We believe the likelihood of any such payment by AEL is remote and as such 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 as the fair value was inconsequential at inception.

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Regulatory Matters

In December 2012, Atlanta Gas Light filed a petition with the Georgia Commission for approval to resolve a volumetric imbalance of natural gas related to Atlanta Gas Light's use of retained storage assets to operationally balance the system for the benefit of the natural gas market. In September 2014, we filed a stipulation that was entered between us, staff of the Georgia Commission and several Marketers that included a resolution of the 4.6 Bcf imbalance over a five-year period from January 1, 2015 through December 31, 2019. The Georgia Commission approved the stipulation in December 2014. Over the five-year period, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, will be used to resolve 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light is obligated to resolve 25% and we have recorded a reserve in our Consolidated Statements of Financial Position representing the future estimated cost to purchase the approximately 1.15 Bcf of natural gas. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all certificated Marketers through charges for system retained storage gas as it is used by the certificated Marketers.

On August 7, 2014, staff of the Illinois Commission and the Citizens Utility Board (CUB) filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services requesting refunds of $18 million and $22 million, respectively. We filed surrebuttal testimony in December 2014 in this proceeding disputing that any refund is due, as Nicor Gas was authorized to enter into these transactions and revenues associated with such transactions reduced rate payers' costs as either credits to the purchased gas adjustment (PGA) or reductions to base rates consistent with then-current Illinois Commission orders governing these activities. We believe these claims engage in hindsight speculation, which is expressly prohibited in a prudence review examination, and we intend to vigorously defend against these claims. Evidentiary hearings are scheduled for March 2015. Similar gas loan transactions were provided in other open review years. The resolution will ultimately be decided by the Illinois Commission. We are currently unable to predict the ultimate outcome and have recorded no liability for this matter.

Environmental Matters

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

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

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

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 consolidated financial statements, including the recording of appropriate liabilities when reasonably estimable.

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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	2014	2013	2012
Current income taxes			
Federal	$113	$164	$8
State	38	35	4
Deferred income taxes			
Federal	184	(8)	128
State	17	(11)	20
Amortization of investment tax credits	(2)	(3)	(3)
Total income tax expense	$350	$177	$157

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	2014	2013	2012
Computed tax expense at statutory rate	$325	$165	$151
State income tax, net of federal income tax benefit	36	20	19
Tax effect of net income attributable to the noncontrolling interest	(7)	(7)	(6)
Amortization of investment tax credits	(2)	(3)	(3)
Affordable housing credits	(2)	(2)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Sale of Compass Energy	-	6	-
Other	2	-	-
Total income tax expense on Consolidated Statements of Income	$350	$177	$157

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. The current portion of our deferred income taxes is recognized within current assets in our Consolidated Statements of Financial Position. 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 current and long-term accumulated deferred income tax liability are as follows.

	As of December 31,	
In millions	2014	2013
Current accumulated deferred income tax liabilities		
Mark-to-market	$33	$-

Inventory	26	18
Total current accumulated deferred income tax liabilities	59	18
Current accumulated deferred income tax assets		
Compensation accruals	30	19
Lower of cost or market	26	-
Allowance for doubtful accounts	12	10
Mark-to-market	-	24
Other	21	16
Total current accumulated deferred income tax assets	89	69
Valuation allowances (1)	(6)	(8)
Total current accumulated deferred income tax assets, net of valuation allowance	83	61
Net current accumulated deferred income tax asset	$24	$43
Long-term accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$1,801	$1,608
Investments in partnerships	16	18
Acquisition intangibles	14	11
Mark-to-market	12	-
Undistributed earnings of foreign subsidiaries	-	26
Other	85	97
Total long-term accumulated deferred income tax liabilities	1,928	1,760
Long-term accumulated deferred income tax assets		
Unfunded pension and retiree welfare benefit obligation	117	92
Deferred investment tax credits	6	7
Mark-to-market	-	3
Other	95	44
Total long-term accumulated deferred income tax assets	218	146
Valuation allowances (1)	(14)	(14)
Total long-term accumulated deferred income tax assets, net of valuation allowance	204	132
Net long-term accumulated deferred income tax liability	$1,724	$1,628

(1) The total valuation allowance in 2014 and 2013 is $20 million and $22 million respectively. For 2014 the total is comprised of $1 million due to net operating losses of a former non-operating facility that are not allowed in New Jersey and $19 million related to our investment in Triton. For 2013 the total is comprised of $3 million due to net operating losses in New Jersey of a former non-operating facility that are not allowed in New Jersey and $19 million related to our investment in Triton. New Jersey net operating losses expired in 2014, resulting in the reduction of the valuation allowance.

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Tax Benefits

As of December 31, 2014, and December 31, 2013, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2015. As of December 31, 2014, 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 2014 or 2013.

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 2011.

Note 13 - Segment Information

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

Effective September 1, 2014, we closed on the sale of Tropical Shipping, which historically operated within our cargo shipping segment. The assets and liabilities of these businesses are classified as held for sale on the Consolidated Statements of Financial Position, and the financial results of these businesses as of December 31, 2013 are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in this note, unless otherwise indicated, exclude assets held for sale and discontinued operations. Cargo shipping also included our investment in Triton, which was not part of the sale and has been reclassified to a non-reportable segment. See Note 14 for additional information.

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

We are also involved in several related and complementary businesses. Our retail operations segment includes retail natural gas marketing to end-use customers primarily in Georgia and Illinois. Additionally, retail operations 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 except Nicor Gas, as well as for non-affiliated companies. Our midstream operations segment includes our non-utility storage and pipeline operations, including the operation of high-deliverability natural gas storage assets. Our “other” non-reportable segments include subsidiaries that individually are not significant on a stand-alone basis and that do not fit into one of our reportable 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 each segment's operations. EBIT includes operating income and other income and expenses. Items we do not include in EBIT are income taxes and financing costs, including interest expense, each of which we evaluate on a consolidated basis. Summarized Statements of Income, Statements of Financial Position and capital expenditure information by segment as of and for the years ended December 31, 2014, 2013 and 2012 are shown in the following tables.

2014

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other segments (2)	Intercompany eliminations	Consolidated
Operating revenues from external parties	$ 3,802	$ 994	$ 578	$ 88	$ 7	$ (84)	$ 5,385
Intercompany revenues	199	-	-	-	-	(199)	-
Total operating revenues	4,001	994	578	88	7	(283)	5,385
Operating expenses							
Cost of goods sold	2,223	683	77	57	-	(275)	2,765
Operation and maintenance	699	147	75	26	-	(8)	939
Depreciation and amortization	317	28	1	18	16	-	380
Taxes other than income taxes	189	4	3	6	6	-	208
Total operating expenses	3,428	862	156	107	22	(283)	4,292
Gain (loss) on disposition of assets	-	-	3	-	(1)	-	2
Operating income (loss)	573	132	425	(19)	(16)	-	1,095
Other income (expense)	8	-	(3)	2	7	-	14
EBIT	$ 581	$ 132	$ 422	$ (17)	$ (9)	$ -	$ 1,109
Identifiable and total assets (3)	$ 12,041	$ 670	$ 1,402	$ 694	$ 9,723	$ (9,621)	$ 14,909
Capital expenditures	$ 715	$ 11	$ 2	$ 15	$ 26	$ -	$ 769

2013

In millions	Consolidated

	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other segments (2)	Intercompany eliminations	
Operating revenues from external parties	$ 3,230	$ 858	$ 60	$ 74	$ 8	$ (21)	$ 4,209
Intercompany revenues	182	-	-	-	-	(182)	-
Total operating revenues	3,412	858	60	74	8	(203)	4,209
Operating expenses							
Cost of goods sold	1,687	564	21	33	-	(195)	2,110
Operation and maintenance	687	132	49	24	3	(8)	887
Depreciation and amortization	339	27	1	17	13	-	397
Taxes other than income taxes	167	3	3	5	9	-	187
Total operating expenses	2,880	726	74	79	25	(203)	3,581
Gain on disposition of assets	-	-	11	-	-	-	11
Operating income (loss)	532	132	(3)	(5)	(17)	-	639
Other income (expense)	14	-	-	(5)	7	-	16
EBIT	$ 546	$ 132	$ (3)	$ (10)	$ (10)	$ -	$ 655
Identifiable and total assets (3)	$ 11,634	$ 685	$ 1,163	$ 713	$ 10,160	$ (10,088)	$ 14,267
Capital expenditures	$ 684	$ 9	$ 2	$ 12	$ 24	$ -	$ 731

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2012

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

(1) The revenues for wholesale services are netted with costs associated with its energy and risk management activities. A reconciliation of our operating revenues and our intercompany revenues for the years ended December 31, are shown in the following table. Wholesale services 2014 operating revenues are related to colder-than-normal weather and extreme volatility and are not indicative of future performance.

In millions	Third party gross revenues	Intercompany revenues	Total gross revenues	Less gross gas costs	Operating revenues
2014	$10,709	$ 718	$11,427	$10,849	$578
2013	7,681	417	8,098	8,038	60
2012	6,089	350	6,439	6,351	88

(2) Our other non-reportable segments now also include our investment in Triton, which was part of our cargo shipping segment that is classified as discontinued operations. For more information, see Note 14.

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

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

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Note 14 - Discontinued Operations

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

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

The assets and liabilities of Tropical Shipping classified as held for sale on the Consolidated Statements of Financial Position are as follows:

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

The financial results of these businesses are reflected as discontinued operations, and all prior periods presented have been recast to reflect the discontinued operations. The components of discontinued operations recorded on the Consolidated Statements of Income as of December 31, are as follows:

In millions	2014	2013	2012
Operating revenues	$243	$365	$342
Operating expenses			
Cost of goods sold	149	222	208

Operation and maintenance (1)	75	110	106
Depreciation and amortization (2)	5	19	22
Taxes other than income taxes	5	6	6
Loss on sale and goodwill impairment (3)	28	-	-
Total operating expenses	262	357	342
Operating (loss) income	(19)	8	-
(Loss) income before income taxes	(19)	8	-
Income tax expense (4)	(61)	3	(1)
(Loss) income from discontinued operations, net of tax	$(80)	$5	$1

(1) Includes $1 million for another business not related to Tropical Shipping that we discontinued in 2014 and was included in our “other” non-reportable segment.

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

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

(4) Includes $60 million that was recorded in 2014 related to the cumulative foreign earnings for which no tax liabilities had been previously recorded.

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Note 15 - 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 sale of our cargo shipping segment in 2014. 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.

Our 2014 operating revenues and operating income were higher than 2013, primarily as a result of significantly colder-than-normal weather in 2014, volatility in the natural gas market and transportation constraints in the Northeast and Midwest. Our quarterly financial data for 2014 and 2013 are summarized below.

In millions, except per share amounts	March 31	June 30	September 30	December 31
2014				
Operating revenues	$2,462	$889	$589	$1,445
Operating income	592	139	78	286
EBIT	595	141	81	292
Income from continuing operations	346	59	23	152
Income from continuing operations attributable to AGL Resources Inc.	334	57	23	148
(Loss) income from discontinued operations, net of tax	(50)	1	(31)	-
Net income (loss) attributable to AGL Resources Inc.	284	58	(8)	148
Basic earnings (loss) per common share:				
Continuing operations	2.82	0.48	0.19	1.24
Discontinued operations	(0.43)	0.01	(0.25)	-
Diluted earnings (loss) per common share:				
Continuing operations	2.81	0.48	0.19	1.24
Discontinued operations	(0.43)	0.01	(0.25)	-
2013				
Operating revenues	$1,612	$805	$574	$1,218
Operating income	290	113	70	166
EBIT	295	119	77	164
Income from continuing operations	159	45	24	80
Income from continuing operations attributable to AGL Resources Inc.	149	44	24	73
Income (loss) from discontinued operations, net of tax	1	(1)	1	4
Net income attributable to AGL Resources Inc.	150	43	25	77
Basic earnings (loss) per common share:				
Continuing operations	1.27	0.38	0.20	0.61
Discontinued operations	0.01	(0.01)	0.01	0.03
Diluted earnings (loss) per common share:				
Continuing operations	1.26	0.38	0.20	0.61
Discontinued operations	0.01	(0.01)	0.01	0.03

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.

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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 the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of December 31, 2014. 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 and considering the remediation efforts described below, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014. Our disclosure controls and procedures are designed to ensure 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 and that such information 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.

Remediation of Previously Disclosed Material Weakness in Internal Control Over Financial Reporting

As previously disclosed in our Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2014, we did not maintain effective controls to appropriately apply the accounting guidance related to the recognition of allowed versus incurred costs. Specifically, the Company did not have controls to address the recognition of allowed versus incurred costs, primarily related to an allowed equity return, applied to the accounting for our regulated infrastructure programs and related disclosures that operated at a level of precision to prevent or detect potential material misstatements to the Company's consolidated financial statements. Our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were not effective as of September 30, 2014 because of the material weakness.

We revised our consolidated financial statements for the years ended December 31, 2013, 2012 and 2011, for each of the quarterly periods during the year ended December 31, 2013, and for the quarters ended March 31, 2014 and June 30, 2014 to reflect certain accounting adjustments. We amended our Annual Report on Form 10-K/A for the year ended December 31, 2013, and our Quarterly Reports on Form 10-Q/A for the quarterly periods ending March 31, 2014 and June 30, 2014, to reflect those adjustments and the conclusions by our principal executive officer and our principal financial officer that our disclosure controls and procedures were not effective and by our management that our internal control over financial reporting were not effective as of December 31, 2013. Refer to "Management's Annual Report on Internal Control over Financial Reporting" within Item 8 and Item 9A Controls and Procedures in our Annual Report on Form 10-K/A for the year ended December 31, 2013, for further discussion of our material weakness in internal control over financial reporting.

We committed to remediating the material weakness and, as such, implemented changes to our internal control over financial reporting. We implemented additional procedures to address the underlying causes of the material weakness prior to filing our amended 2013 Annual Report on Form 10-K/A, and continued to implement changes and improvements in our internal control over financial reporting to remediate the control deficiency that caused the material weakness. During the fourth quarter of 2014, the following actions have been implemented:

- Completed training for all appropriate personnel regarding the applicable accounting guidance and requirements through internal training meetings and training by an outside expert to employees in technical, general and regulatory accounting functions, internal audit, and management positions.
    - Reviewed all regulatory programs to ensure the proper evaluation of deferral components and proper treatment of allowed versus incurred costs pursuant to the relevant accounting guidance.
- Created a process and designed controls to capture and calculate allowed versus incurred costs and to record appropriate amounts in the consolidated financial statements. We identified appropriate processes, reviews and other controls to ensure accurate amounts were appropriately reflected in our consolidated financial statements.
- Conducted a review of our organization structure, reporting relationships and adequacy of staffing levels and made specific staffing changes as a result of our review.
    - The procedures described above have been implemented and controls have been successfully tested.

Management is committed to a strong internal control environment. With full implementation and testing of the design and operating effectiveness of the newly implemented and revised controls, the actions described above successfully remediated the material weakness in our internal control over financial reporting and our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective and our management concluded that our internal control over financial reporting were effective as of December 31, 2014.

Changes in Internal Control over Financial Reporting

The changes in the aforementioned remediation efforts were changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2014, 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, 2014. The unqualified reports of management and PricewaterhouseCoopers LLP are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

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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 59	
Chairman, President and Chief Executive Officer	October 2007 - Present
Andrew W. Evans, Age 48	
Executive Vice President and Chief Financial Officer	November 2010 - Present
Executive Vice President, Chief Financial Officer and Treasurer	June 2009 - November 2010
Henry P. Linginfelter, Age 54	
Executive Vice President, Distribution Operations	December 2011 - Present
Executive Vice President, Utility Operations	June 2007 - December 2011
Melanie M. Platt, Age 60	
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 57	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 - Present
Peter I. Tumminello, Age 52	
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,” and “Corporate Governance - Committees of the Board” in the Proxy Statement for our 2015 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 Committee Report,” “Compensation 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 Committee Report” which is specifically not so incorporated herein by reference.

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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 2015” 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.

- Report of Independent Registered Public Accounting Firm
- Management’s Report on Internal Control Over Financial Reporting

(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, 2014 and 2013
- Consolidated Statements of Income for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Equity for the years ended December 31, 2014, 2013 and 2012
- Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012
- 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, 2014. 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
2.3	Stock Purchase Agreement by and among Aqua Acquisition Corp., Ottawa Acquisition LLC and Birdsall, Inc.(1)	AGL Resources	November 25, 2014, Form 10-Q/A, Exhibit 2
3.1	Amended and Restated Articles of Incorporation	AGL Resources	December 13, 2011, Form 8-K, Exhibit 3.1
3.2	Bylaws, as amended	AGL Resources	July 31, 2014, 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

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4.3.b	Guarantee of AGL Resources Inc. dated December 20, 2004	AGL Resources	December 21, 2004, Form 8-K, Exhibit 4.3
4.4.a	AGL Capital Corporation 6.375% Senior Notes due 2016	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.1
4.4.b	Guarantee of AGL Resources Inc. dated December 14, 2007	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.2
4.5.a	AGL Capital Corporation 5.25% Senior Notes due 2019	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.1
4.5.b	Guarantee of AGL Resources Inc. dated August 10, 2009	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.2
4.6.a	AGL Capital Corporation 5.875% Senior Notes due 2041	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.1
4.6.b	Guarantee of AGL Resources Inc. dated March 21, 2011	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.2
4.7.a	Form of AGL Capital Corporation 3.50% Senior Notes due 2021	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.1
4.7.b	Form of Guarantee of AGL Resources Inc. dated September 2011	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.2
4.8.a	Form of AGL Capital Corporation Series A Senior Notes due 2016	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.1
4.8.b	Form of AGL Capital Corporation Series B Senior Notes due 2018	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.2
4.9.a	AGL Capital Corporation 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.9.b	AGL Resources Inc. Guarantee related to the 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.10.a	Indenture dated December 1, 1989	Atlanta Gas Light	File No. 33-32274, Form S-3, Exhibit 4(a)
4.10.b	First Supplemental Indenture dated March 16, 1992	Atlanta Gas Light	File No. 33-46419, Form S-3, Exhibit 4(a)
4.11	Indenture dated February 20, 2001	AGL Resources	September 17, 2001, File No. 333-69500, Form S-3, Exhibit 4.2
4.12.a	Indenture dated January 1, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.01
4.12.b	Indenture dated February 9, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.02
4.12.c	Supplemental Indenture dated February 15, 1998	Nicor Gas	December 31, 1997, Form 10-K, Exhibit 4.19
4.12.d	Supplemental Indenture dated May 15, 2001	Nicor Gas	July 20, 2001, File No. 333-65486, Form S-3, Exhibit 4.18
4.12.e	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.09
4.12.f	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.10
4.12.g	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.11
4.12.h	Supplemental Indenture dated December 1, 2006	Nicor Gas	December 31, 2006, Form 10-K, Exhibit 4.11

4.12.i	Supplemental Indenture dated August 1, 2008	Nicor Gas	September 30, 2008, Form 10-Q, Exhibit 4.01
4.12.j	Supplemental Indenture dated July 23, 2009	Nicor Gas	June 30, 2009, Form 10-Q, Exhibit 4.01
4.12.k	Supplemental Indenture dated February 1, 2011	Nicor Gas	December 31, 2010, Form 10-K, Exhibit 4.12
4.12.l	Supplemental Indenture dated October 26, 2012	Nicor Gas	September 30, 2012, Form 10-Q, Exhibit 4
10.1.a+	2006 Non-Employee Directors Equity Compensation Plan, amended and restated as of December 9, 2011	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.2
10.1.b+	1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 1997, Form 10-Q, Exhibit 10.1.b
10.1.c+	First Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	March 31, 2000, Form 10-Q, Exhibit 10.5
10.1.d+	Second Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.4
10.1.e+	Third Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	September 30, 2002, Form 10-Q, Exhibit 10.5
10.1.f+	Fourth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	June 30, 2007, Form 10-Q, Exhibit 10.1.m
10.1.g+	Fifth Amendment to the 1998 Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.l

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

10.1.ab+	Second Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ab
10.1.ac+	Third Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ac
10.1.ad+	Description of Supplemental Executive Retirement Plan for John W. Somerhalder II	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.ay
10.1.ae+	Excess Benefit Plan as amended and restated as of January 1, 2009	AGL Resources	December 31, 2008, Form 10-K, Exhibit 10.1.az
10.1.af +	Form of Continuity Agreement dated December 19, 2013	AGL Resources	December 19, 2013, Form 8-K, Exhibit 10.1
10.1.ag+	Description of compensation for each of John W. Somerhalder II, Andrew W. Evans, Henry P. Linginfelter, Paul R. Shlanta and Peter I. Tumminello (our Named Executive Officers for the year ended December 31, 2014)	AGL Resources	Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held April 29, 2014, filed March 18, 2014.
10.2.a	Form of Commercial Paper Dealer Agreement	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.79
10.2.b	Guarantee dated October 5, 2000 of payments on promissory notes	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.80
10.4	Note Purchase Agreement dated August 31, 2011	AGL Resources	September 7, 2011, Form 8-K, Exhibit 10.1
10.5	Final Allocation Agreement dated January 3, 2008	Nicor	December 31, 2007, Form 10-K, Exhibit 10.64

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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(2)	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.1
10.8.a	Amended and Restated Credit Agreement dated as of November 10, 2011(3)	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) Portions of this exhibit have been omitted pursuant to a request for confidential treatment with the SEC. The omitted portions have been separately filed with the SEC.

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

(3) 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).

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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 11, 2015.

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, 2014, 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 11, 2015.

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/ 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

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Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2014.

		Additions			
In millions	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Deductions	Balance at end of period
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
2014					
Allowance for uncollectible accounts	$29	$54	$2	$(50)	$35
Income tax valuation	22	-	-	(2)	20