AGL RESOURCES INC
Form 10-K
February 11, 2016

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, 2015
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. has (1) 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) 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 2015 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 Part III, Item 11 of this Form 10-K.
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, 2015, as reported by the New York Stock Exchange) was $5,591,017,687.
The number of shares of AGL Resources Inc.’s common stock outstanding as of February 5, 2016 was 120,384,325.

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GLOSSARY OF KEY TERMS

AFUDC	Allowance for funds used during construction
AGL Capital	AGL Capital Corporation
AGL Credit Facility	$1.3 billion credit agreement entered into by AGL Capital to support its 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
Board	AGL Resources Board of Directors
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
CUB	Citizens Utility Board
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 interest on debt and income tax expense
EPA	U.S. Environmental Protection Agency
ERC	Environmental remediation costs
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings
Florida Commission	Florida Public Service Commission, the state regulatory agency for Florida City Gas
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 weather, calculated when the average daily temperatures are less than 65 degrees Fahrenheit
Heating Season	The period from November through March when natural gas usage and operating revenues are generally higher
Henry Hub	An interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced
Horizon Pipeline	Horizon Pipeline Company, LLC
	Illinois Commerce Commission, the state regulatory agency for Nicor Gas

Illinois Commission	
Jefferson Island	Jefferson Island Storage & Hub, LLC
LIBOR	London Inter-Bank Offered Rate
LIFO	Last-in, first-out
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Merger Agreement	Agreement and Plan of Merger dated August 23, 2015 by Southern Company, AMS Corp., a subsidiary of Southern Company, and AGL Resources
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. - 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
PBR	Performance-based rate
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
PRP	Pipeline Replacement Program, Atlanta Gas Light's 15-year infrastructure replacement program, which ended in December 2013
S&P	Standard & Poor's Ratings Services
Sawgrass Storage	Sawgrass Storage, LLC
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
Southern Company	The Southern Company
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, which was sold in 2014
U.S.	The United States of America
VaR	Value-at-risk
VIE	Variable interest entity

Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas
Virginia Natural Gas	Virginia Natural Gas, Inc.
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,” “the company” or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries. AGL Resources was incorporated in 1995 under the laws of the State of Georgia and is headquartered in Atlanta, Georgia.

Business Overview

AGL Resources is an energy services holding company whose primary business is the safe, reliable and cost-effective distribution of natural gas through seven natural gas distribution utilities. We also are involved in several other businesses that are complementary to the distribution of natural gas. Our reportable segments, listed below, reflect how management views and manages our businesses. Our non-reportable subsidiaries are aggregated and presented as "other." In August 2015, we entered into the Merger Agreement with Southern Company, which we expect to become effective in the second half of 2016. For more information on this transaction, see Note 2 to our consolidated financial statements under Item 8 herein.

Distribution Operations	• Operates, constructs and maintains 81,300 miles of natural gas pipeline and 14 storage facilities, with total capacity of 158 Bcf, to provide natural gas to residential, commercial and industrial customers • Serves 4.5 million customers across seven states • Rates of return are regulated by each individual state in return for exclusive franchises
Retail Operations	• Provides natural gas commodity and related services to customers in competitive markets or markets that provide for customer choice • Serves 645,000 energy customers in seven states and 1.2 million service contracts across 17 states
Wholesale Services	• Engages in natural gas storage and gas pipeline arbitrage, and provides natural gas asset management and related logistics services for most of our utilities, as well as 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 wholly owned natural gas storage facilities as well as partnerships and joint ventures in pipelines, enabling the provision of diverse sources of natural gas supplies to our customers

For more segment information, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Results of Operations” and Note 14 to our consolidated financial statements in 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	2,198	34,300
Atlanta Gas Light	Georgia	1,578	32,900
Virginia Natural Gas	Virginia	290	5,600
Elizabethtown Gas	New Jersey	283	3,200
Florida City Gas	Florida	107	3,600
Chattanooga Gas	Tennessee	64	1,600
Elkton Gas	Maryland	6	100
Total		4,526	81,300

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 in our service areas for customers who are

considering switching to or from a natural gas appliance. Accordingly, the potential displacement or replacement of natural gas appliances is a competitive factor.
Competition for 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 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 of the U.S. have resulted in historically high supplies of natural gas and relatively 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 regulatory agencies. 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 regulatory agencies. 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

Our utilities are subject to regulations and oversight of the regulatory agencies in each of the states served 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, 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 our infrastructure replacement programs as well as our 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 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, encourages 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.

Dollars in millions	Nicor Gas	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
Authorized return on rate base (1)	8.09%	8.10%	7.64%	7.38%	7.36%	7.41%
Estimated 2015 return on rate base (2)	7.20%	7.65%	7.83%	5.83%	4.40%	6.82%
Authorized return on equity (1)	10.17%	10.75%	10.30%	10.00%	11.25%	10.05%
Estimated 2015 return on equity (2)	9.66%	9.86%	10.70%	7.43%	5.80%	8.74%
Authorized rate base % of equity (1)	51.07%	51.00%	47.89%	45.36%	36.77%	46.06%
Rate base included in 2015 return on equity (2)	$1,654	$2,352	$555	$615	$194	$117
Weather normalization (3)			ü	ü		ü
Decoupled, including straight-fixed-variable rates (4)		ü		ü		ü
Regulatory infrastructure program rates (5)	ü	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 (9)	2009	2010	2009	2011	2004	2010

(1) The authorized return on rate base, return on equity and rate base percentage of equity represent those authorized as of December 31, 2015.

(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 on earnings of weather and customer consumption. 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) Allows 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 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) Elizabethtown Gas has agreed to file a general rate case with the New Jersey BPU by September 2016.

Infrastructure Replacement Programs and 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 our customers, provide an appropriate return on invested capital and ensure the safety and reliability of our utility infrastructure. Total capital expenditures incurred during 2015 for our distribution operations segment were $957 million. The following table and discussions provide updates on some of our larger capital projects under various programs at our utilities, which update or expand our distribution systems to improve reliability and meet operational flexibility and growth. Our anticipated expenditures for these programs in 2016 are discussed in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," under the caption "Liquidity and Capital Resources."

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Utility	Program	Program details	Recovery	Expenditures in 2015 (in millions)	Expenditures since project inception (in millions)	Miles of pipe installed since project inception	Scope of program (miles)	Program duration (years)	Last year of program
Nicor Gas	Investing in Illinois	(1)(2)	Rider	252	273	164	800	9	2023
Atlanta Gas Light	Integrated Vintage Plastic Replacement Program (i-VPR)	(3)	Rider	63	130	398	756	4	2017
Atlanta Gas Light	Integrated System Reinforcement Program (i-SRP)	(8)	Rider	44	309	n/a	n/a	8	2017
Atlanta Gas Light	Integrated Customer Growth Program (i-CGP)	(9)	Rider	15	62	n/a	n/a	8	2017
Florida City Gas	Safety, Access and Facility Enhancement Program (SAFE)	(4)	Rider	1	1	4	254	10	2025
Virginia Natural Gas	Steps to Advance Virginia's Energy (SAVE)	(1)	Rider	27	91	163	250	5	2017
Elizabethtown Gas	Aging Infrastructure Replacement (AIR)	(5)	Base Rates	39	77	75	130	4	2017
Chattanooga Gas	Bare Steel & Cast Iron	(5)	Base Rates	5	38	84	111	10	2020
Florida City Gas	Galvanized Replacement Program	(6)	Base Rates	—	15	79	111	17	2017
Atlanta Gas Light	Savannah Backyard Main	(4)	Base Rates	4	14	59	98	5	2017
Elizabethtown Gas	Elizabethtown Natural Gas Distribution Utility Reinforcement Effort	(7)	Base Rates	11	14	12	13	1	2015

(ENDURE)				
Total	461	1,024	1,038	2,523

(1) Cast iron, bare steel, mid vintage plastic and risk based materials.
(2) Represents expenditures on qualifying infrastructure that have been placed into service after the rate freeze expiration date, December 9, 2014.
(3) Early vintage plastic, risk based mid vintage plastic, mid vintage neighborhood convenience.
(4) Backyard main replacement.
(5) Cast iron and bare steel.
(6) Galvanized and X-Tube steel. Reflects expenditures and miles of pipe installed since we acquired Florida City Gas in November 2004.
(7) Cast iron and distribution reinforcement.
(8) Large diameter pressure improvement and system reinforcement projects.
(9) New business construction and strategic line extension.

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 nine-year regulatory infrastructure program, Investing in Illinois, under which we implemented rates that became effective in March 2015. As of December 31, 2015, we have placed into service $250 million of qualifying projects under this plan, which represents approximately 1.5% of annual average base rate revenues for 2015.

Atlanta Gas Light Our four-year STRIDE program, which was approved in December 2013, is comprised of i-SRP, i-CGP and i-VPR and consists of infrastructure development, enhancement and replacement programs that are used to update and expand distribution systems and liquefied natural gas facilities, improve system reliability and meet operational flexibility and growth. STRIDE includes a monthly surcharge on firm customers that was approved by the Georgia Commission to provide recovery of the revenue requirement for the ongoing programs and the PRP, which ended on December 31, 2013. This surcharge began in January 2015 and will continue through 2025.

The i-SRP program authorized $445 million of capital spending for projects 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 along with a new construction plan every three years for review and approval by the Georgia Commission. Our most recent plan was filed in August 2013 and approved in February 2014.

Our i-CGP authorizes Atlanta Gas Light to spend $91 million on projects to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

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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 should potentially 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.

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 third year performance rate update was approved by the Virginia Commission in July 2015 and became effective in August 2015. In November 2015, Virginia Natural Gas filed with the Virginia Commission for approval of an extension to the SAVE program through 2021.

Elizabethtown Gas Our extension of the AIR 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 in our pipeline system. Carrying charges on the additional capital spend are being accrued and deferred for regulatory purposes at a 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 Natural Gas Distribution Utility Reinforcement Effort (ENDURE), a program that improved our distribution system's resiliency against coastal storms and floods. Under the plan, Elizabethtown Gas invested $15 million in infrastructure and related facilities and communication planning over a one year period from August 2014 through September 2015. Effective November 1, 2015, Elizabethtown Gas increased its base rates for investments made under the program.

In September 2015, we filed the Safety, Modernization and Reliability Tariff (SMART) plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel and copper pipeline, as well as 240 regulator stations. If approved, the program is expected to be completed by 2027. As currently proposed, costs incurred under the program would be recovered through a rider surcharge over a period of 10 years.

Florida City Gas In September 2015, the Florida Commission approved our Safety, Access and Facility Enhancement (SAFE) program, under which costs incurred for replacing aging pipes will be recovered through a rate rider with annual adjustments and true-ups. Under the program, we expect to spend $105 million over a 10-year period on infrastructure relocation and enhancement projects. Florida City Gas began spending under the program during the fourth quarter of 2015 and plant in service associated with work performed in 2015 was included in the calculation of rates that began January 1, 2016.

Current Regulatory Proceedings

Atlanta Gas Light In February 2015, Atlanta Gas Light made a filing with the Georgia Commission for a rate true-up of allowed unrecovered revenue of $178 million through December 2014 related to its PRP. In October 2015, Atlanta Gas Light received a final order from the Georgia Commission allowing Atlanta Gas Light to recover $144 million of the $178 million. The remaining unrecovered amount relates primarily to recoveries of previously allowed rate of return amounts, which are included in our unrecognized ratemaking amount and does not have a material impact on our consolidated financial statements as of December 31, 2015. As a result of the order, we recognized $1 million of interest expense on our Consolidated Statements of Income in 2015 related to the PRP true-up.

We began recovering the $144 million in October 2015 through a monthly PRP surcharge, which increased by $0.82 on October 1, 2015 and will increase by an additional $0.81 on each of October 1, 2016 and October 1, 2017. The cumulative total monthly increase to the PRP surcharge will remain at $2.44 and be effective until the earlier of the full recovery of the under-recovered amount or December 31, 2025.

Additionally, one of the capital projects under the PRP experienced construction issues on certain segments in late 2013, and prior to these segments being placed into service, it was necessary to complete mitigation work. The order from the Georgia Commission allows for the recovery of these mitigation costs in future base rates, but such recovery will be effective no earlier than March 31, 2017. As a result of the order we recognized $5 million in operation and maintenance expense on our Consolidated Statements of Income in 2015. Atlanta Gas Light continues to pursue contractual and legal claims against certain third-party contractors in connection with the mitigation costs relating to these construction issues. Any amounts recovered through the legal process will be retained by Atlanta Gas Light. At March 31, 2017, the total capitalized mitigation cost for which Atlanta Gas Light will seek recovery in future rates is approximately $28 million.

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In December 2014, the Georgia Commission approved a stipulation 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. During the first half of 2015, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, were used to resolve the Georgia Commission's obligation of 25% of the total 4.6 Bcf imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light was also obligated to resolve 25% of the imbalance through system injections, which were fully replaced by the end of the third quarter of 2015. The cost to resolve the remaining difference of approximately 2.3 Bcf of natural gas will be recovered from all of the Marketers over the five-year period permitted by the stipulation through charges for system retained storage gas as it is used by the Marketers.

In accordance with an order issued by the Georgia Commission, when AGL Resources makes a business acquisition that reduces the costs allocated or charged to Atlanta Gas Light for shared services, the net savings to Atlanta Gas Light will be shared equally between the firm customers of Atlanta Gas Light and our shareholders for a ten-year period. In March 2015, the Georgia Commission approved the Report of Synergy Savings that we filed in connection with the Nicor merger. The net savings result in annual rate reductions of $5 million to the firm customers of Atlanta Gas Light. These surcredit adjustments are now a component of the Atlanta Gas Light base charge and began appearing on customers’ bills in June 2015.

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. All refunds were completed by the first half of 2014. The CUB's February 2014 appeal of the Illinois Commission's order requesting refunds consistent with its 2009 request was rejected by the appellate court in March 2015.

In August 2014, staff of the Illinois Commission and the CUB filed testimony in the 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services and requesting refunds of $18 million and $22 million, respectively. In July 2015, the Administrative Law Judge issued a proposed order concluding that Nicor Gas' supply costs and purchases in 2003 were prudent, its reconciliation of the related costs was proper, and the propositions by the staff of the Illinois Commission and the CUB were based on hindsight speculation, which is expressly prohibited in a prudence review examination. In September 2015, the Illinois Commission issued a final order approving the proposal of the Administrative Law Judge. In November 2015, the Illinois Commission granted the CUB's petition for a rehearing on this matter, with action required by the Illinois Commission by April 2016. Additionally, in December 2015, all parties agreed on a plan to move forward with hearings on certain other open PGA reconciliation years. In February 2016, the Administrative Law Judge issued a proposed order on rehearing affirming the original order by the Illinois Commission, which now requires approval by the Illinois Commission. We are currently unable to predict the ultimate outcomes and have recorded no liability for these matters.

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 49 million therms, which was in excess of our planned goal of saving 40 million therms over the duration of this program. Additionally, in May 2014, the Illinois Commission approved Nicor Gas’ second energy efficiency program, energySMART, with expected spending of $93 million over a three-year period and an estimated therm reduction goal of 27 million therms. The program began in June 2014 and Nicor Gas spent $31 million in 2015 and $14 million in 2014 and have achieved approximately 17 million in therm reduction as of December 31, 2015. The costs incurred on the program will be recovered over a three-year period through a rider surcharge.

Asset Management Agreements

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. Nicor Gas has not entered into an asset management agreement with Sequent or any other parties. For Atlanta Gas Light, these payments are controlled by the Georgia Commission and are 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, but 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.

Each agreement provides for Sequent to make payments to the utilities through either an annual minimum guarantee within a profit sharing structure, a profit sharing structure without an annual minimum guarantee, or a fixed fee. From the inception of these agreements in 2001 through 2015, Sequent made sharing payments to our utilities under these agreements totaling $332 million. The following table provides payments made by Sequent to our utilities under these agreements during the last three years.

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	Total amount received			
In millions	2015	2014	2013	Expiration Date
Elizabethtown Gas	$28	$18	$6	March 2019
Virginia Natural Gas	15	14	4	March 2018
Atlanta Gas Light	15	13	6	March 2017
Florida City Gas	1	1	1	(1)
Chattanooga Gas	1	1	1	March 2018
Total	$60	$47	$18	

(1) The agreement renews automatically each year unless terminated by either party.

Natural Gas 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, Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas operate on-system LNG facilities, underground natural gas storage fields and propane/air plants to meet the gas supply and deliverability requirements of our customers during the winter. Generally, we work to build a portfolio of year-round firm transportation, seasonal storage and short-duration peaking services to 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 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 with staggered terms to maintain our ability to adjust the overall portfolio to meet changing market conditions. Our utilities have contracted for capacity that is predominantly sourced from producing areas in the midcontinent and gulf coast regions, and they continue to evaluate capacity options that will provide long-term access to reliable and affordable natural gas supplies. We make decisions as to the termination, extension or renegotiation of contracts every year.

In 2014, our midstream operations segment entered into three pipeline projects that will provide access to shale gas in proximity to 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.

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 former MGP sites. As we continue to conduct MGP remediation and enter into cleanup contracts, we are able to refine our engineering estimates of the likely costs. These estimates contain various engineering assumptions, which we refine and update on an ongoing basis. These costs are primarily recovered through rate riders. See Note 4 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 is comprised of SouthStar and Pivotal Home Solutions, which serve approximately 645,000 natural gas commodity customers and 1.2 million service contracts.

SouthStar is one of the largest retail natural gas marketers in the U.S. and markets natural gas to residential, commercial and industrial customers, primarily in Georgia, Illinois and Ohio, where we capture spreads between wholesale and retail natural gas prices. We also offer our customers energy-related products that provide natural gas price stability and utility bill management. These products mitigate or eliminate the risks to customers of colder-than-normal weather and 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 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. On December 9, 2015, we notified Piedmont of our election, in accordance with the terms in the Second Amended and Restated Limited Liability Company Agreement of SouthStar, to purchase its entire 15% interest in

SouthStar at fair market value. The parties currently are negotiating final terms.

Pivotal Home Solutions provides a suite of home protection products and services that offers 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. We serve customers in several states, primarily Illinois, Indiana, Massachusetts and Ohio. We continue to expand product offerings to customers of 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.

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Competition and Operations SouthStar participates in various customer choice programs that were approved in various states to increase competition in natural gas markets. These programs are implemented by each state and vary by size, scope and participation. The customer choice programs provide for the ability of residential and commercial customers to choose their own natural gas supplier while the local distribution company continues to provide transportation and distribution services. The Georgia market continues to be the most comprehensive choice program in the U.S., whereby all of Atlanta Gas Light's customers purchase their natural gas directly from Marketers. SouthStar operates as Georgia Natural Gas and is the largest of 14 Marketers in Georgia, with average customers of nearly 500,000 and a leading market share of approximately 30%. SouthStar also operates within other customer choice markets that do not have the high level of customer participation as Georgia. SouthStar's ability to grow within these markets is dependent upon customer awareness of these programs primarily through marketing and continued participation by each state in these programs.

In Georgia, 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, many of SouthStar’s residential and commercial customers have migrated to fixed-price plans, which combined with increased competition from other Marketers has impacted our customer growth and 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 utilities. SouthStar’s retail pricing strategies and the use of a variety of hedging strategies, such as 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 “Weather and Natural Gas Price Risks.” Our retail operations businesses also experience price, convenience, and service competition from other warranty 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 our customers. Our customers consist primarily of electric and natural gas utilities, power generators and large industrial customers. Our logistical expertise enables us to provide our customers with natural gas from the major producing regions and market hubs. We also leverage our portfolio of natural gas storage assets and contracted natural gas supply, transportation and storage capacity to meet our delivery requirements and customer obligations at competitive prices.

Wholesale services’ portfolio of storage and transportation capacity enables us to generate additional operating margin as opportunities arise by optimizing the contracted assets through the application of our wholesale market knowledge and risk management skills. 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.

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.

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The second perspective is the value 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 prior to the period the related physical storage and transportation transactions occur and are recognized in earnings. The changes in fair values of the hedging instruments are recognized in earnings in the period of change and are 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 the natural gas is physically withdrawn from storage or transported and sold at market prices and the related hedging instruments are settled.

We purchase natural gas for our storage portfolio when the current market price we pay plus the cost for transportation, storage and financing is less than the market price we anticipate receiving 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 manage costs, reduce price volatility and maintain a competitive advantage.

Midstream Operations

Storage and Fuels Our midstream operations segment includes a number of businesses that are related and complementary to our primary business of the safe and reliable delivery of natural gas. 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 and select pipeline investments.

Pipelines In 2014, we entered into three pipeline projects, which are currently awaiting FERC approval. These projects, along with our existing pipelines, 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 following table provides an overview of these pipeline projects. See Note 11 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)		FERC filing	Expected FERC approval
Atlantic Coast Pipeline (2)	564	$260	5	%	2015	2016
PennEast Pipeline (3)	118	200	20	%	2015	2016
Dalton Pipeline (4)	106	210	50	%	2015	2016
Total	788	$670				

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

(2) 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.

(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 recent winters.

(4) 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.
Magnolia Enterprise Holdings, Inc. This wholly owned subsidiary operates a pipeline that connects our Georgia service territory to LNG imports and 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 that expires 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 2015, expiring storage capacity contracts were re-subscribed at lower prices and we anticipate these lower natural gas prices to

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continue in 2016 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" segment is an aggregation of AGL Services Company, AGL Capital, our investment in Triton and our other subsidiaries that individually are not significant on a stand-alone basis and that do not align with our reportable segments. 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; however, we do incur certain corporate costs that are not allocated to our reportable segments. Our EBIT results for our reportable segments include the impact of such operating expenses and the permitted allocations. 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. Triton is a full service global leasing company and owner-lessor of marine intermodal cargo containers.

Employees

As of December 31, 2015, we had 5,203 employees, all of whom were in the U.S. The following table provides information about our natural gas utilities' collective bargaining agreements, which represent 33% of our total employees.

	Number of employees	Contract expiration date
Nicor Gas		
International Brotherhood of Electrical Workers (Local No. 19)	1,422	February 2017
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50) (1)	137	May 2019
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424) (2)	166	November 2019
Total	1,725	

(1) Virginia Natural Gas' collective bargaining agreement expired in May 2015, and a new agreement was ratified in August 2015. The new agreement provides for additional operational enhancements and changes to certain benefits, but has no material effect on our consolidated financial statements.

(2) Elizabethtown Gas' collective bargaining agreement expired in November 2015, and a new agreement was ratified in December 2015. The new agreement provides for additional operational enhancements and changes to certain benefits, but has no material effect on our consolidated financial statements.

We believe that we have a good working relationship with our unionized employees and there have been no work stoppages since we acquired those operations. As we have done historically, we remain committed to working 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

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.

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ITEM 1A. RISK FACTORS

Forward-Looking Statements

Certain expectations and projections regarding our future performance referenced in this section and elsewhere in this report, as well as in other reports and proxy statements we file with the SEC or otherwise release to the public and on our website are forward-looking statements and are subject to uncertainties and risks. Senior officers and other employees may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements often include words such as "anticipate," "assume," "believe," "can," "could," "estimate," "expect," "forecast," "future," "goal," "indicate," "intend," "may," "outlook," "plan," "potential," "predict," "project," "proposed," "seek," "should," "target," "would" or similar expressions. You are cautioned not to place undue reliance on 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 of which are 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:

- certain risks and uncertainties associated with the proposed merger with Southern Company, including, without limitation:
- the possibility that the proposed merger does not close due to the failure to satisfy the closing conditions, including, but not limited to, a failure to obtain the required regulatory approvals;
- delays caused by required regulatory approvals, which may delay the proposed merger or cause the companies to abandon the transaction;
- disruption from the proposed merger making it more difficult to maintain our business and operational relationships and the risk that unexpected costs will be incurred during this process; and
- the diversion of management time on merger-related issues;
- 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, 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;
- 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 capacity of our gas storage caverns, which are subject to natural settling and other occurrences;
- contracting rates at our midstream operations storage business;
- the impact of our construction projects and related capital expenditures, including our pipeline projects;
- the development, timing and anticipated costs relating to our pipeline projects;
- the impact of changes in weather 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;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- the other factors discussed elsewhere herein and in our other filings with the SEC.

There may also be other factors that we do not anticipate or that we do not recognize as material that could cause results to differ materially from our expectations. Forward-looking statements speak only as of the date they are made. We expressly disclaim any obligation to 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 regulatory infrastructure 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 obtain the rate increases that we request in a timely manner, should we not 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.

The price for natural gas and competing energy sources, such as oil, can fluctuate widely. Generally, we pass through changes in prices to our utility customers, 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, which results in additional financing costs as a result of purchasing more expensive natural gas.

In addition, increases in natural 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 the desired 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.

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 natural gas for 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 natural gas, the cost of natural 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 natural 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/or 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. 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.

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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 55% of all usage is for heating and approximately 73% 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 5,845 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 3 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.
SouthStar offers 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 operational interruptions.
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 4 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 additional debt borrowings. 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.

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We may be exposed to regulatory and financial risks related to the impact of climate change legislation and regulation.
Climate change legislation is receiving increased 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. Below is a summary of recent global and federal actions related to climate change legislation.

In December 2015, the U.S. and 195 other nations adopted the United Nations sponsored Paris Agreement on global climate change (Paris Agreement), which establishes a universal framework for addressing greenhouse gas emissions based on nationally determined contributions. It also sets in place a process for increasing those commitments every five years. The ultimate impact of the Paris Agreement depends on its ratification and implementation by participating countries, and cannot be determined at this time.

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, the 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 directed 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 directed the EPA to finalize those regulations by June 1, 2015. The EPA complied and issued the commonly referred to Clean Power Plan, which seeks to reduce carbon dioxide emissions from existing electric utility generating units by 30% from 2005 levels and promotes increased use of natural gas and renewable energy. States are required to develop regulations implementing the EPA's guidelines by September 6, 2016 and may seek a two-year extension. It also includes a wide variety of other initiatives designed to reduce greenhouse gas emissions and lead international efforts to address climate change.

The outcome of global, federal and state climate change legislation 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. Future regulation of methane, a greenhouse gas and primary constituent of natural gas, 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.

Transporting and storing natural gas involves 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, 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 also rely on natural gas pipelines and other storage and transportation facilities owned and operated by third parties to deliver natural gas to wholesale markets and to our distribution systems.

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, 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.

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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 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 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 natural gas prices and low volatility, and we expect this to continue in 2016.

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 significant credit losses.

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 14 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 local distribution utilities, 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 wholesale services and the commodity and storage portfolios at midstream operations and retail operations 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 “Weather and Natural Gas Price Risks – VaR” herein.

Our accounting results may not be indicative of the risks we are taking or the economic results we expect in our nonregulated businesses.

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

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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 plan 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 plan 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 7 to the consolidated financial statements under Item 8 herein.

Natural disasters, terrorist activities, human error 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 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 had no material security breaches in 2015.

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We may pursue acquisitions, divestitures and other strategic transactions, 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 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.

Future impairments of goodwill or long-lived assets could have a material adverse effect on our results of operations.

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. In the third quarter of 2015, we recorded a non-cash impairment charge of $14 million ($9 million, net of tax) of goodwill in our midstream operations segment. No impairment of goodwill was recorded as a result of our 2015 annual impairment testing for any of our other segments, as the fair value of each reporting unit was in excess of the carrying value. See Note 3 to our consolidated financial statements under Item 8 herein for additional information on impairment of assets. Additionally, no impairment of long-lived assets was recorded during 2015.

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. Due to the subjectivity of the assumptions and estimates underlying the impairment analysis, future analyses may 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 these 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 and 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 and related interest rate swaps, which could lead to changes in interest expense and adversely affect our earnings.

We are subject to interest rate risk 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 restriction. In addition, Nicor Gas is not permitted to make money pool loans to affiliates.

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.

Risk Factors Related to the Merger Agreement

The merger is subject to receipt of consent or approval from various governmental entities that could delay or prevent the completion of the merger or, in order to receive such consent or approval, the governmental entities may impose restrictions or conditions that could have a material adverse effect on the combined company or that could cause abandonment of the transaction.

Completion of the merger is contingent upon, among other things, satisfaction or waiver of specified closing conditions, including (i) the receipt of required regulatory approvals from the Federal Communications Commission, California Public Utilities Commission, Georgia Commission, Illinois Commission, Maryland Commission, New Jersey BPU and Virginia Commission, and such approvals having become final orders and (ii) the absence of a

judgment, order, decision, injunction, ruling or other finding or agency requirement of a governmental entity prohibiting the consummation of the merger. For more information, see Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” under the caption “Executive Summary” and the subheading “Proposed Merger With Southern Company” and Note 2 to the consolidated financial statements under Item 8 herein.
We may not receive the required statutory approvals and other clearances for the merger, or we may not receive them in a timely manner. If such approvals and clearances are received, they may impose terms, conditions or restrictions (i) that cause a failure of the closing conditions set forth in the Merger Agreement, which could permit us or Southern Company to terminate the Merger Agreement and abandon the transaction or (ii) that could reasonably be expected to have a detrimental impact on the combined company following completion of the merger. A substantial delay in obtaining the required authorizations, approvals or consents or the imposition of unfavorable terms, conditions or restrictions contained in such authorizations, approvals or consents could prevent the completion of the merger or have an adverse effect on the anticipated benefits of the merger, thereby impacting the business, financial condition or results of operations of the combined company.
Notwithstanding the expiration of the waiting period under the Hart-Scott-Rodino Act, governmental authorities could seek to block or challenge the merger as they deem necessary or desirable in the public interest.

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Failure to complete the merger could adversely affect our stock price, future business operations and financial results.
Completion of the merger is subject to risks, including the risks that approval of the transaction by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If we are unable to complete the merger, our ongoing business may be adversely affected and we would be subject to a number of risks, including the following:

- we will have paid certain significant transaction costs, including legal, financial advisory and filing, printing and mailing fees, and in certain circumstances, a termination fee to Southern Company of $201 million;
- the attention of our management may have been diverted to the merger rather than to our operations and the pursuit of other opportunities that could have been beneficial to us;
- the potential loss of key personnel during the pendency of the merger as employees may experience uncertainty about their future roles with the combined company;
- we will have been subject to certain restrictions on the conduct of our business, which may prevent us from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger is pending; and
- the trading price of our common stock may decline to the extent that the current market price reflects a market assumption that the merger will be completed.

A failure to complete the merger may also result in negative publicity, additional litigation against the company or its directors and officers, and a negative impression of the company in the investment community. The occurrence of any of these events individually or in combination could have a material adverse effect on our results of operations or the trading price of our common stock.

We are subject to contractual restrictions in the Merger Agreement that may hinder operations pending the merger.
The Merger Agreement restricts the Company, without Southern Company's consent, from making certain acquisitions and taking other specified actions until the merger occurs or the Merger Agreement terminates. For instance, the Company is limited in the amount of indebtedness for borrowed money it may incur and additional common shares that it may issue. These restrictions may prevent us from pursuing otherwise attractive business opportunities and making other changes to our business prior to completion of the merger or termination of the Merger Agreement.

We will be subject to various uncertainties while the merger is pending that may cause disruption and may make it more difficult to maintain relationships with employees, suppliers or customers.
Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on us. Although we intend to take steps designed to reduce any adverse effects, these uncertainties may impair our abilities to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, and could cause customers, suppliers and others that deal with us to seek to change or terminate existing business relationships with us or not enter into new relationships or transactions.

Employee retention and recruitment may be particularly challenging prior to the completion of the merger, as employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite our retention and recruiting efforts, key employees depart or fail to continue employment with us because of issues relating to the uncertainty and difficulty of integration or a desire not to remain with the combined company, our financial results could be adversely affected. Furthermore, the combined company’s operational and financial performance following the merger could be adversely affected if it is unable to retain key employees and skilled workers. The loss of the services of key employees and skilled workers and their experience and knowledge regarding our business could adversely affect the combined company’s future operating results and the successful ongoing operation of its businesses.

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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.

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, 2015, our distribution operations segment owned approximately 81,300 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 approximately 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 total LNG storage capacity of approximately 7.6 Bcf. In addition, we own one propane storage facility in Virginia with 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, Inc., 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 any 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 12 to our consolidated financial statements under the caption “Litigation” under Item 8 herein.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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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 5, 2016, there were 20,743 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2015 and 2014 is as follows:

	Sales price of common stock		Cash dividend per		Sales price of common stock		Cash dividend per
Quarter ended:	High	Low	common share	Quarter ended:	High	Low	common share
March 31, 2015	$57.75	$46.50	$0.51	March 31, 2014	$49.84	$45.17	$0.49
June 30, 2015	51.88	46.45	0.51	June 30, 2014	55.10	48.29	0.49
September 30, 2015 (1)	63.37	46.36	0.51	September 30, 2014	55.30	48.72	0.49
December 31, 2015	63.99	60.55	0.51	December 31, 2014	56.67	50.10	0.49
			$2.04				$1.96

(1) On August 23, 2015, we entered into the Merger Agreement with Southern Company.

We have paid 272 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" under the captions "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, legal requirements and other factors.

Issuer Purchases of Equity Securities

Except for common stock returned to us by employees in satisfaction of withholding tax requirements and exercise consideration for stock options, there were no purchases of our common stock by us or any affiliated purchasers during the three months ended December 31, 2015. There were 93,842 shares of common stock returned to us by employees related to equity awards for the three months ended December 31, 2015.

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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 on our Consolidated Statements of Income. The operations of our former Tropical Shipping business, which was sold during 2014, are reflected as discontinued operations in 2014 and all prior periods have been recast to reflect the discontinued operations. Material changes from 2013 to 2014 and 2014 to 2015 are due primarily to increased earnings from our wholesale services segment in 2014 that resulted mainly from the extreme weather and associated natural gas price volatility. 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	2015	2014	2013	2012	2011
Income statement data					
Operating revenues	$3,941	$5,385	$4,209	$3,562	$2,305
Income from continuing operations	373	580	308	274	179
(Loss) income from discontinued operations, net of tax	—	(80)	5	1	—
Net income	373	500	313	275	179
Less net income attributable to the noncontrolling interest	20	18	18	15	14
Net income attributable to AGL Resources	$353	$482	$295	$260	$165
Net income attributable to AGL Resources					
Income from continuing operations attributable to AGL Resources	$353	$562	$290	$259	$165
(Loss) income from discontinued operations, net of tax	—	(80)	5	1	—
Net income attributable to AGL Resources	$353	$482	$295	$260	$165
Per common share information					
Diluted weighted average common shares outstanding	119.9	119.2	118.3	117.5	80.9
Diluted earnings (loss) per common share					
Continuing operations	$2.94	$4.71	$2.45	$2.20	$2.04
Discontinued operations	—	(0.67)	0.04	0.01	—
Diluted earnings per common share attributable to AGL Resources common shareholders	$2.94	$4.04	$2.49	$2.21	$2.04
Cash dividends declared per common share	$2.04	$1.96	$1.88	$1.74	$1.90
Dividend payout ratio	69%	49%	76%	79%	93%
Dividend yield (1)	3.2%	3.6%	4.0%	4.4%	4.5%
Price range:					
High	$63.99	$56.67	$49.31	$42.88	$43.69
Low	$46.36	$45.17	$38.86	$36.59	$34.08
Close (2)	$63.81	$54.51	$47.23	$39.97	$42.26
Market value (2)	$7,681	$6,522	$5,615	$4,711	$4,946
Balance sheet data (2)					
Total assets (3) (4)	$14,754	$14,888	$14,528	$14,051	$13,841
Property, plant and equipment, net	9,791	9,090	8,643	8,205	7,741
Long-term debt (4)	3,820	3,781	3,791	3,533	3,555
Total equity	3,975	3,828	3,613	3,391	3,305

Financial ratios [2]					
Debt	55 %	56 %	58 %	59 %	60 %
Equity	45 %	44 %	42 %	41 %	40 %
Total	100 %	100 %	100 %	100 %	100 %
Return on average equity	9.0 %	13.0 %	8.4 %	7.8 %	6.4 %

(1) 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.

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

(3) Total assets for 2011-2013 include assets held for sale, which reflect the assets of our former Tropical Shipping business.

(4) Total assets and long-term debt for 2011-2014 have been adjusted to reflect the netting of debt issuance costs with its debt carrying amount in accordance with our 2015 adoption of new accounting guidance related to this balance sheet presentation.

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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 safe, reliable and cost-effective 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 our primary business. We have four reportable segments – 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 discontinued operations. See Note 15 to our consolidated financial statements under Item 8 herein for additional information regarding discontinued operations. The following table shows the proportion of certain financial metrics attributable to our segments.

	EBIT			Assets			Capital expenditures		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Distribution operations	76 %	52 %	84 %	85 %	81 %	82 %	93 %	93 %	93 %
Retail operations	20	12	20	5	5	5	1	1	1
Wholesale services	14	38	—	6	9	8	—	—	—
Midstream operations	(3)	(1)	(2)	5	5	5	3	2	2
Other/intercompany eliminations	(7)	(1)	(2)	(1)	—	—	3	4	4
Total	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %	100 %

Business Objectives Our priorities for 2016 are consistent with the direction we have taken the company over the last several years. We will remain focused on safe and efficient operations across all of our businesses, improving customer satisfaction and awareness of the benefits of our product and investment in infrastructure for the future. Several of our specific business objectives are detailed as follows:

- Distribution Operations: Invest necessary capital to enhance and maintain safety and reliability in delivering natural gas; remain an efficiency leader within the industry while maintaining a focus on customer satisfaction; expand the natural gas distribution system and educate energy consumers on the benefits of converting to natural gas. We intend to continue investing in our regulatory infrastructure programs to minimize the lag in recovery of our capital. We continue to effectively manage costs and leverage our shared services model across our businesses to combat inflationary effects.
- Retail Operations: Maintain our current customer base in Georgia and Illinois while continuing to expand into other profitable retail markets and expand our warranty businesses through partnership opportunities with affiliates and third parties. We will focus on products that are responsive to our customers' needs.
- Wholesale Services: 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 relative to other marketers.
- Midstream Operations: Invest in natural gas based projects, some of which remain subject to regulatory approvals, along with our existing pipelines and storage to 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. For additional information on our pipeline projects, see Note 3 and Note 11 to our consolidated financial statements under Item 8 herein and Item 1, "Business" under the caption "Midstream Operations."

Additionally, we intend to 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 14 to our consolidated financial statements under Item 8 herein and Item 1, "Business."

Performance and Non-GAAP Measures We evaluate segment performance using the measures of EBIT and operating margin. EBIT includes operating income and other income and expenses and excludes interest expense and income taxes, 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 expenses, depreciation and amortization, taxes other than income taxes, merger-related expenses, goodwill impairment charges and the gain or loss on the sale of our assets, which are included in our calculation of operating income as calculated in accordance with GAAP and reflected on our Consolidated Statements of Income.

We believe that the presentation of operating margin provides useful information to management and investors regarding 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 further believe that operating margin at our retail operations, wholesale services and midstream operations segments allows us to focus on a direct measure of operating margin before overhead costs.

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We present the non-GAAP measure of diluted earnings per share - as adjusted, which exclude merger-related expenses and a non-cash goodwill impairment charge at midstream operations. As we do not regularly engage in transactions of the magnitude of the proposed merger with Southern Company, and consequently do not regularly incur merger expenses of correlative size, we believe presenting diluted earnings per share excluding merger expenses provides investors with an additional measure of our core operating performance. We also have chosen to exclude a non-cash goodwill impairment related to our midstream operations segment because management believes that investors may find it useful to assess our core operating performance without this non-cash item.

Operating margin and diluted earnings per share - as adjusted should not be considered as alternatives to, or more meaningful indicators of, our operating performance than net income attributable to AGL Resources, operating income or diluted earnings per share from continuing operations as determined in accordance with GAAP. In addition, our operating margin and diluted earnings per share - as adjusted may not be comparable to similarly titled measures of other companies.

Summary of Results:

The table below reconciles (i) operating revenues and operating margin to operating income, (ii) EBIT to income before income taxes and net income and (iii) non-GAAP diluted earnings per share - as adjusted to GAAP diluted earnings per common share from continuing operations, together with other consolidated financial information for the last three years.

In millions, except per share amounts	2015	2014	2013
Operating revenues (1)	$3,941	$5,385	$4,209
Cost of goods sold	(1,645)	(2,765)	(2,110)
Revenue tax expense (2)	(101)	(130)	(110)
Operating margin	2,195	2,490	1,989
Operating expenses (3)	(1,550)	(1,527)	(1,471)
Revenue tax expense (2)	101	130	110
Gain on disposition of assets	—	2	11
Operating income	746	1,095	639
Other income	13	14	16
EBIT	759	1,109	655
Interest expense, net	(173)	(179)	(170)
Income before income taxes	586	930	485
Income tax expense	(213)	(350)	(177)
Income from continuing operations	373	580	308
(Loss) income from discontinued operations, net of tax	—	(80)	5
Net income	373	500	313
Less net income attributable to the noncontrolling interest	20	18	18
Net income attributable to AGL Resources	$353	$482	$295
Net income attributable to AGL Resources			
Income from continuing operations attributable to AGL Resources	$353	$562	$290
(Loss) income from discontinued operations, net of tax (4)	—	(80)	5
Net income attributable to AGL Resources	$353	$482	$295
Per common share data			
Diluted earnings per common share from continuing operations	$2.94	$4.71	$2.45
Diluted (loss) earnings per common share from discontinued operations (4)	—	(0.67)	0.04
Merger-related expenses	0.23	—	—
Goodwill impairment	0.07	—	—
Diluted earnings per share - as adjusted	$3.24	$4.04	$2.49

(1) Our revenues declined significantly in 2015 compared to 2014 primarily due to lower natural gas prices and lower volumes of gas sold to customers due to weather in 2015 that was warmer than the extreme cold experienced in 2014.

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

(3) Operating expenses for 2015 include $44 million of merger-related expenses and a $14 million goodwill impairment charge.

(4) In September 2014, we sold Tropical Shipping. See Note 15 to our consolidated financial statements under Item 8 herein for additional information.

2015 Results In 2015, our income from continuing operations attributable to AGL Resources decreased by $209 million, or 37%, compared to 2014. This decrease was due primarily to lower consolidated EBIT of $350 million, largely driven by wholesale services, and was partially offset by lower income tax expense of $137 million due to lower earnings in 2015.

Included in the 2015 EBIT were $44 million of merger-related expenses and a $14 million non-cash goodwill impairment charge at our midstream operations segment. Excluding these items and the $314 million year-over-year change in results of wholesale services, EBIT increased by $22 million in 2015, compared to 2014, primarily as a result of the following:

- $34 million in additional operating margin at distribution operations from regulatory infrastructure programs, partially offset by $19 million in higher depreciation expense.
- $19 million in additional operating margin at retail operations due to the recovery of prior year hedge losses and lower current year derivative losses resulting from changes in natural gas prices.

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- These increases were partially offset by weather at distribution operations and retail operations due to significantly warmer temperatures in 2015, compared to 2014.

Wholesale services reported $108 million of EBIT in 2015, compared to $422 million in 2014, a decrease of $314 million. In 2014, wholesale services benefited from increased natural gas volatility that was generated by significantly colder-than-normal weather through higher commercial activity and net hedge gains. Wholesale services continued to benefit from market volatility in 2015 and generated EBIT that was significantly higher than its average economic earnings expectation of $50 million.

2014 Results In 2014, our income from continuing operations attributable to AGL Resources 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 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 from a reduction in the estimated cavern capacity as a result of naturally occurring shrinkage, 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 an $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.

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

Proposed Merger With Southern Company In August 2015, we entered into the Merger Agreement with Southern Company, which, based on the number of common shares and the fair value of debt outstanding as of December 31, 2015, reflects an estimated business enterprise value of AGL Resources of $13.0 billion, including a total equity value of $7.9 billion. When the merger becomes effective, which is expected to occur in the second half of 2016, each share of our common stock, other than certain excluded shares, will convert into the right to receive $66 in cash, without interest, less any applicable withholding taxes. Completion of the merger is conditioned upon, among other things, the approval of certain state utility and other regulatory agencies. On November 19, 2015, the proposed merger was approved by our shareholders at a special meeting. At closing, the transaction is expected to create the second largest utility in the U.S. by customer base and we will become a wholly owned subsidiary of Southern Company and continue to maintain our own management team. For additional information relating to this transaction, see Note 2 and Note 12 to our consolidated financial statements under Item 8 herein. See Item 1A, "Risk Factors" herein for information on the merger-related risks.

Results of Operations

Operating Revenues We generate the majority of our operating revenues through the sale, distribution and storage of natural gas. Our consolidated revenues include an estimate of revenues from natural gas distributed, but not yet billed to our 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	2015	2014	2013
Residential	$2,129	$2,877	$2,422
Commercial	617	861	696
Transportation	526	458	487
Industrial	203	242	180
Other (1)	466	947	424
Total operating revenues	$3,941	$5,385	$4,209

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

Operating metrics Our operating metrics of weather impact, customer count, natural gas volumes and the seasonality of our operating results are presented below.

Weather We measure weather and its effect on our business by using Heating Degree Days. Generally, increased Heating Degree Days result in higher demand for gas on our distribution systems. With the exception of Nicor Gas and Florida City Gas, we have regulatory mechanisms, such as weather normalization, which limit our exposure to weather changes within typical ranges in each of our utilities' respective service areas. However, our utility customers in Illinois and our retail operations customers in Georgia can be impacted by warmer- or colder-than-normal weather. Additionally, we utilize weather hedges at distribution operations and retail operations to reduce negative earnings impacts in the event of warmer-than-normal weather, while retaining all of the earnings upside in the event of colder-than-normal weather for distribution operations in Illinois and most of the earnings upside for our retail operations. We also consider operating costs that may vary with the effects

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of weather, particularly in periods that are significantly colder-than-normal. The following table presents the Heating Degree Days information for those locations.

	Years ended December 31,				2015 vs. 2014	2014 vs. 2013	2015 vs. normal	2014 vs. normal	2013 vs. normal
	Normal (1)	2015	2014	2013	(warmer)	colder	(warmer)	colder	colder
Illinois (2)	5,845	5,433	6,556	6,305	(17)%	4%	(7)%	12%	8%
Georgia	2,628	2,204	2,882	2,689	(24)%	7%	(16)%	10%	2%

(1) Normal represents the 10-year average from January 1, 2005 through December 31, 2014, 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 5,600 for the 12 months from 1998 through 2007.

In 2015, we experienced weather in Illinois that was 7% warmer-than-normal and 17% warmer than 2014. In the first quarter of 2015 weather in Illinois was 10% colder-than-normal, while weather in the fourth quarter of 2015 was 28% warmer-than-normal in Illinois. Since we hedged our Illinois weather risk for these quarterly periods separately and hedged only exposure for warmer-than-normal weather, the EBIT impact of weather for the year was favorable by $2 million, net of the impact of our weather hedging for distribution operations. The colder-than-normal weather in Illinois in 2014 primarily drove an EBIT increase of $22 million, for distribution operations, based on 10-year normal weather. For our retail operations in Georgia, weather in 2015 was 16% warmer-than-normal and 24% warmer than the same period last year. Similar to our strategy for distribution operations, because we hedged weather risk for our retail operations for the first and fourth quarters separately and hedged exposure for warmer-than-normal weather, the EBIT impact of weather for the year was slightly unfavorable by $1 million in 2015. The colder-than-normal weather increased EBIT by $8 million in 2014 compared to expected levels based on 10-year normal weather for our retail operations.

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 presented in the following table highlight the average number of customers to which we provided services for the specified periods.

	Years ended December 31,			2015 vs. 2014 change		2014 vs. 2013 change	
In thousands	2015	2014	2013	#	%	#	%
Distribution operations customers (1)	4,526	4,497	4,479	29	0.6%	18	0.4%
Retail operations							
Energy customers (2)	645	628	619	17	3%	9	1%
Service contracts (3)	1,171	1,182	1,127	(11)	(1)%	55	5%
Market share in Georgia	29.7%	30.6%	31.4%		(0.9)%		(0.8)%

(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 compared to 2013.

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

(3) Includes approximately 43,000 customer warranty contracts acquired in Connecticut and Massachusetts in the second half of 2015.

We anticipate overall customer growth trends at distribution operations for 2015 to continue in 2016 as we expect continued improvement in the economy, the related housing market and 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 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 2016, we intend to continue efforts in our retail operations segment to enter into targeted markets and expand energy customers and service contracts. We anticipate this expansion will provide growth opportunities in future years.

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

	Year ended December 31,			2015 vs. 2014	2014 vs. 2013
Distribution operations (In Bcf)	2015	2014	2013	% change	% change
Firm	695	766	720	(9)%	6%
Interruptible	99	106	111	(7)	(5)
Total	794	872	831	(9)%	5%
Retail operations (In Bcf)					
Georgia firm	35	41	38	(15)%	8%
Illinois	13	17	9	(24)	89
Other (includes Florida, Maryland, Michigan, New York and Ohio)	11	10	8	10	25
Wholesale services					
Daily physical sales (Bcf/day)	6.79	6.32	5.73	7%	10%

Within midstream operations, 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 its earnings and maximize the value of its investments.

Our midstream operations storage business is cyclical, and the abundant supply of natural gas in recent years and resulting lack of market and price volatility have negatively impacted the profitability of our storage facilities. The rates at which we may re-contract expiring capacity may not be as high as expected and may also remain below historical averages in 2016. The prices for natural gas storage capacity are expected to increase as supply and demand quantities reach equilibrium with continued economic improvement, expected exports of LNG, and projected demand increases in response to low prices and expanded uses for natural gas. The following table contains the overall monthly average firm subscription rates per facility and amount of firm capacity subscription for all periods presented. These amounts exclude 5 Bcf contracted by Sequent as of December 31, 2015, at an average monthly rate of $0.080 and 7 Bcf as of December 31, 2014, at an average monthly rate of $0.050.

	December 31, 2015		December 31, 2014	
	Average rates (per dekatherm)	Firm capacity under subscription (Bcf)	Average rates (per dekatherm)	Firm capacity under subscription (Bcf)
Jefferson Island	$0.092	4.2	$0.108	4.6
Golden Triangle	0.041	5.0	0.114	5.0
Central Valley	0.047	4.0	0.062	2.5

Seasonality of our Results During the Heating Season, natural gas usage and operating revenues are generally higher as more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather. 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 Balance Sheets 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, bad debt 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, which is illustrated in the table below.

	Percent generated during Heating Season	
	Revenues	EBIT
2015	70%	80%
2014	73	81

2013	68	72

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Segment Information

Three years of operating margin, operating expenses and EBIT information for each of our segments is contained in the following table. See Note 14 to our consolidated financial statements under Item 8 herein for additional segment information.

	Operating Margin (1) (2)			Operating Expenses (2)			EBIT (1)		
In millions	2015	2014	2013	2015 (3)	2014	2013	2015	2014	2013 (4)
Distribution operations	$1,657	$1,648	$1,615	$1,086	$1,075	$1,083	$580	$581	$546
Retail operations	317	311	294	165	179	162	152	132	132
Wholesale services	183	501	39	71	79	53	108	422	(3)
Midstream operations	36	31	41	62	50	46	(23)	(17)	(10)
Other	7	7	8	70	22	25	(58)	(9)	(10)
Intercompany eliminations	(5)	(8)	(8)	(5)	(8)	(8)	—	—	—
Consolidated	$2,195	$2,490	$1,989	$1,449	$1,397	$1,361	$759	$1,109	$655

(1) Operating margin is a non-GAAP measure. A reconciliation of operating margin to operating revenues and operating income, and a reconciliation of EBIT to income before income taxes and net income is contained in "Results of Operations" herein.

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

(3) Operating expenses for 2015 include a $14 million goodwill impairment charge recorded during the third quarter at midstream operations and $44 million of merger-related expenses recorded within our other segment.

(4) EBIT for 2013 includes an $11 million pre-tax gain on the sale of Compass Energy in wholesale services and an $8 million pre-tax loss associated with the termination of the Sawgrass Storage project within midstream operations.

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 states we serve. These agencies approve natural gas rates designed to provide us the opportunity to generate revenues to recover the cost of natural gas delivered to our customers and our fixed and variable costs, such as depreciation, interest, maintenance and overhead costs, and to earn a reasonable return for our shareholders.

With the exception of Atlanta Gas Light, our second largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for natural gas consumed. We have various weather mechanisms, such as weather normalization mechanisms and weather derivative instruments, that limit our exposure to weather changes within typical ranges in their respective service areas.

In millions	2015	2014
EBIT - prior year	$581	$546
Operating margin		
Increase from regulatory infrastructure programs, primarily at Atlanta Gas Light and Nicor Gas	34	10
Increase mainly driven by non-weather-related customer usage and growth	13	22
Decrease in rider program recoveries at Nicor Gas, offset by operating expenses below	(18)	(12)
(Decrease) increase in weather-related customer usage, net of weather hedging	(20)	13
Increase in operating margin	9	33
Operating expenses		
Increase in depreciation expense primarily due to additional assets placed in service during 2015 and 2014. 2014 was offset by the impact of Nicor Gas' new composite depreciation rate that became effective August 30, 2013	19	(22)
Increase in benefit expenses primarily related to higher pension costs and health benefits in 2015 and lower pension costs in 2014 due to changes in actuarial gains and losses	12	(13)

Increase in payroll and variable compensation costs as a result of merit increases in 2015 and 2014 as well as higher incentive compensation in 2014	9	19
Increase due to write-off PRP-related costs from the global settlement	5	—
(Decrease) increase in bad debt expenses due to changes in natural gas consumption and prices	(2)	4
(Decrease) increase in weather-related expenses	(4)	5
(Decrease) increase in outside services and other expenses primarily due to maintenance programs	(5)	11
Decrease in fleet expenses from lower fuel prices	(5)	—
Decrease in rider program recoveries at Nicor Gas, offset by operating margin above	(18)	(12)
Increase (decrease) in operating expenses	11	(8)
Decrease in other income in 2014 primarily relates to STRIDE projects at Atlanta Gas Light	1	(6)
EBIT - current year	$580	$581

Retail Operations Our retail operations segment consists of several businesses that provide energy related products and services to retail markets. Retail operations is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to partially mitigate potential weather impacts. In 2015, we recovered $15 million of prior period hedge losses and LOCOM adjustments as the underlying transactions were recognized at higher margins. The net effect is that the transactions ultimately resulted in the expected economic outcome at the time the derivatives were executed to manage the associated price risk.

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In millions	2015	2014
EBIT - prior year	$132	$132
Operating margin		
Recovery of hedge losses (gains)	12	(1)
Increase (decrease) in value of unrealized derivatives as a result of NYMEX natural gas prices	7	(13)
LOCOM adjustments, net of recoveries	3	(5)
Improved warranty margins	2	6
Decrease in 2015 due to customer mix. Increase in 2014 due primarily to lower gas costs and customer count	(8)	13
(Decrease) increase in weather-related customer usage, net of weather hedging	(9)	8
Increase due to 2013 acquisitions	—	9
Other	(1)	—
Increase in operating margin	6	17
Operating expenses		
(Decrease) increase in outside services, variable compensation costs and marketing expenses	(8)	14
(Decrease) increase in depreciation and amortization	(3)	1
(Decrease) increase in bad debt expenses	(1)	1
Other	(2)	1
(Decrease) increase in operating expenses	(14)	17
EBIT - current year	$152	$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 that can result from a number of factors, including weather fluctuations and changes in supply or demand for natural gas in different regions of the country. However, when market price volatility increases as we experienced in both 2015 and 2014, we are well positioned to capture significant value and generate stronger results. 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	2015	2014
EBIT - prior year	$422	$(3)
Operating margin		
(Decrease) increase in commercial activity largely driven by the transportation and storage portfolios in the Northeast and Midwest	(304)	319
(Decrease) increase in value of storage derivatives as a result of fluctuations in NYMEX natural gas prices	(41)	102
(Decrease) increase in value of transportation and forward commodity derivatives from price movements related to natural gas transportation positions	(27)	111
LOCOM adjustments, net of recoveries	54	(66)
Decrease due to sale of Compass Energy in May 2013	—	(4)
(Decrease) increase in operating margin	(318)	462
Operating expenses		
(Decrease) increase related to incentive compensation expenses driven by higher earnings and other costs in 2014	(8)	28
Decrease due to sale of Compass Energy in May 2013	—	(2)
(Decrease) increase in operating expenses	(8)	26
Decrease in other income, primarily related to the gain on sale of Compass Energy	(4)	(11)

EBIT - current year	$108	$422

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

In millions	2015	2014	2013
Commercial activity recognized	$140	$444	$129
Gain (loss) on storage derivatives	45	86	(16)
Inventory LOCOM adjustment, net of estimated current period recoveries	(13)	(67)	(1)
Gain (loss) on transportation and forward commodity derivatives	11	38	(73)
Operating margin	$183	$501	$39

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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. The significant variances in commercial activity between 2015 and 2014 and between 2014 and 2013 are due largely to the recognition of significantly higher operating margin in 2014 associated with our transportation and storage portfolios, particularly in the Northeast and Midwest regions, from price volatility generated by the extreme and prolonged cold weather in that year. Additionally, 2015 operating margin was lower resulting from the withdrawal of storage inventory hedged at the end of 2014 relating to 2015 withdrawals that was included in the storage withdrawal schedule with a value of $(5) million as of December 31, 2014 compared to the comparable measure in 2014 of $28 million related to inventory hedged at the end of 2013. Operating margin in 2014 was also higher resulting from mark-to-market accounting derivative losses at the end of 2013. These mark-to-market losses were recovered in 2014 when the underlying related transactions were recognized at their higher values.

Change in storage and transportation derivatives Continued price volatility in 2015 benefited wholesale services' portfolio of pipeline transportation and storage capacity assets throughout the U.S., primarily in the Northeast market. Although we do not expect this high level of price volatility to continue, we see the potential for market fundamentals indicating some level of increased volatility that would continue to benefit wholesale services should this occur. Storage derivative gains in 2015 and 2014 are primarily due to declines in natural gas prices applicable to the locations of our specific storage assets. These derivative gains were partially offset by LOCOM adjustments to natural gas inventories, net of estimated hedging recoveries.

Gains in our transportation and forward commodity derivative positions in 2015 are primarily due to the narrowing of transportation basis spreads associated with warmer-than-normal weather, which impacted forward prices at natural gas receipt and delivery points, primarily in the Northeast region. Gains in our transportation and forward commodity derivative positions in 2014 are primarily the result of narrowing transportation basis spreads. Transportation and forward commodity hedge losses in 2013 were the result of widening transportation basis spreads, and were largely 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 quarters of both 2015 and 2014 leading to significant decreases in natural gas prices, wholesale services recorded LOCOM adjustments of $19 million and $73 million for the years ended December 31, 2015 and 2014, respectively.

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 and delivery points 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 U.S. 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 the first quarter of 2015 and 2014, 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, largely the result of significantly colder-than-normal weather primarily in the first quarter.

While market conditions in 2014 and early 2015 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, volatility could increase. While natural gas supply increased during the 2013/2014 and 2014/2015 Heating Seasons in the U.S., it was not enough to meet the increased demand, resulting in storage levels that were lower than historical periods. The warm 2015 winter weather experienced in the U.S. resulted in record natural gas inventories that contributed to reduced natural gas prices. Additional economic factors may contribute to this environment,

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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.

The expected natural gas withdrawals from storage, including the expected offset to prior hedge losses/gains associated with our transportation portfolio at December 31, 2015 are presented in the following table, along with the net operating revenues expected at the time of withdrawal from storage and the physical flow of natural gas between contracted transportation receipt and delivery points. Our expected net operating revenues exclude storage and transportation demand charges, and 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, 2015. A portion of wholesale services' storage inventory and transportation capacity is economically hedged with futures contracts, which results in the realization of substantially fixed net operating revenues, timing notwithstanding. The timing of future withdrawals may change in response to changes in future economic value or other factors.

	Storage withdrawal schedule			
Dollars in millions	Total storage (in Bcf) (WACOG $2.27)	Expected net operating gains (1)	Physical transportation transactions – expected net operating gains (losses) (2)	
2016	70	$6	$(17	)
2017 and thereafter	5	2	6	
Total at December 31, 2015	75	$8	$(11	)

(1) Represents expected operating gains from planned storage withdrawals associated with existing inventory positions and could change as wholesale services 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 in 2014 and 2015.

The unrealized storage and transportation derivative gains do not change the underlying economic value of our storage and transportation positions and, based on current expectations, will primarily be reversed in 2016 when the related transactions occur and are recognized. For more information on wholesale services' energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Weather and Natural Gas Price Risks." 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. During 2015, midstream operations' EBIT was negatively impacted by a $14 million non-cash goodwill impairment that was recorded in the third quarter.

In millions	2015		2014	
EBIT - prior year	$(17	)	$(10	)
Operating margin				
Retained fuel true-up recorded in 2014 due to naturally occurring cavern shrinkage	11		(10	)
Lower firm revenues due to recontracting expiring contracts at lower subscription rates and lower interruptible revenue in 2014 compared to 2013	(2	)	(6	)
Decrease in revenue from dewater activity at Golden Triangle in 2014	(5	)	6	
Other	1		—	
Increase (decrease) in operating margin	5		(10	)

Operating expenses		
Goodwill impairment	14	—
(Decrease) increase in operating expenses largely due to a favorable property tax settlement in 2015, outside service cost, depreciation expense and other	(2)	4
Increase in operating expenses	12	4
Increase in other income, 2014 primarily related to the impairment loss at Sawgrass Storage in December 2013	1	7
EBIT - current year	$(23)	$(17)

Other Our "other" segment includes our investment in Triton, AGL Services Company and AGL Capital as well as various corporate operating expenses that we do not allocate to our reportable segments. During 2015, such operating expenses included $44 million of merger-related transaction costs, $8 million for the deductible related to insured losses and $3 million of accelerated expenses related to the retirement of our former Chief Executive Officer.

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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 generally 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, subject to certain limitations. We regularly evaluate our funding strategy and profile to ensure that we have sufficient liquidity for our short-term and long-term needs in a cost-effective manner.

Our financing activities, including long-term and short-term debt and equity, are subject to customary approval or review by the state agencies in which we conduct business as well as the FERC. 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 may be subject to regulation. By regulation, Nicor Gas is restricted, to the extent of its retained earnings balance, in the amount it can dividend or loan to affiliates and is not permitted to make money pool loans to affiliates. Additionally, Elizabethtown Gas is restricted by their dividend policy as established by the New Jersey BPU in the amount it can dividend to AGL Resources to the extent of 70% of its quarterly net income.

We believe the amounts available to us under our long-term debt and credit facilities as well as through the issuance of additional debt, combined with cash provided by operating activities will continue to allow us to meet our needs for working capital, capital expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments and other cash needs through the next several years.

The ability to satisfy our working capital requirements and our debt service obligations, or fund planned capital expenditures, substantially depends 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, 2015, our variable-rate debt was $1.3 billion, or 28%, of our total debt, compared to $1.5 billion, or 31%, as of December 31, 2014. The decrease was primarily due to reduced commercial paper borrowings resulting from warmer weather that resulted in lower natural gas sales as well as the lower cost of gas in 2015. For more information on our debt, see Note 9 to our consolidated financial statements under Item 8 herein.

On November 18, 2015, AGL Capital issued $250 million in 10-year senior notes at a fixed interest rate of 3.875%. The net proceeds from the senior notes of $248 million, which are guaranteed by AGL Capital, were used to repay a portion of AGL Capital's commercial paper, including $200 million we borrowed to repay senior notes that matured on January 15, 2015.

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 the anticipated issuances of senior notes in the fourth quarter of 2015 and in 2016. We designated the forward-starting interest rate swaps, which mature on the respective debt issuance dates, as cash flow hedges. We settled $200 million of these interest rate swaps on November 18, 2015, in conjunction with the aforementioned senior note issuance. The remaining $600 million of interest rate swaps, which had a fair value of $9 million as of December 31, 2015, are expected to be settled in 2016. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Interest Rate Risk" for additional information.

Our objective remains to maintain a strong balance sheet and liquidity profile, solid investment grade ratings and 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	$471	$382	$106	$787
Commercial paper - Nicor Gas	539	349	133	585
Current portion of long-term debt	545	270	—	545
Total	$1,555	$1,001	$239	$1,917

(1) As of December 31, 2015.
(2) For the twelve months ended December 31, 2015.

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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. The largest and minimum balances outstanding for each debt instrument occurred at different times during the period. Consequently, the total balances are not indicative of actual borrowings on any one day during the period. Cash requirements generally increase between June and December as we purchase natural gas in advance of the Heating Season. The timing differences between payment to our suppliers for natural gas purchases and recovery of 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, which 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 at either the alternative base rate plus an applicable interest 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, 2015 and 2014, we had no outstanding borrowings under either credit facility.

The timing of natural gas withdrawals is dependent on the weather and natural gas market conditions, both of which impact the price of natural gas. Increasing natural gas commodity prices can significantly impact our commercial paper borrowings. Based on our total debt outstanding as of December 31, 2015, and our maximum 70% debt to total capitalization allowed under our financial covenants, we could borrow an additional $798 million of commercial paper under the AGL Credit Facility and an additional $162 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.

In October 2015, we entered into agreements to amend and extend our credit facilities. Under the terms of these agreements, we extended the maturity dates of the AGL Credit Facility and Nicor Gas Credit Facility to November 9, 2018 and December 14, 2018, respectively. One of the banks elected not to participate in this extension and its total commitment of $75 million will continue through the fourth quarter of 2017. We also modified the credit facilities to provide for the limited consent by the lenders to the proposed merger with Southern Company. Additionally, we made similar changes to our Bank Rate Mode Covenants Agreement.

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, 2015. It is possible that one or more lending commitments could be unavailable to us if a 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, 2015 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 our level of capital expenditures, long-term debt maturities and decisions to refinance long-term debt. The following table summarizes our long-term debt issuances and refinancings over the last three years.

	Issuance / refinance date	Amount (in millions)	Term (in years)	Interest rate	
Senior notes [1]	November 2015	$250	10	3.9	%
Senior notes [2]	May 2013	$500	30	4.4	%
Gas facility revenue bonds [3]	March 2013	$200	10-20	Floating rate	

(1) The net proceeds were used to repay a portion of AGL Capital's commercial paper, including $200 million we borrowed to repay senior notes that matured on January 15, 2015.

(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.

(3) There were no cash receipts or payments in connection with the refinancing of these gas facility revenue bonds.

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.

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Factors we consider important to assessing our credit ratings include our Consolidated Balance Sheets, 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. 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. As of December 31, 2015, if our credit rating had fallen below investment grade, we would have been required to provide collateral of $19 million to continue conducting business with certain customers.

The table below summarizes our credit ratings as of December 31, 2015.

	AGL Resources			Nicor Gas		
	S&P (1)	Moody's(2) (3)	Fitch (1)	S&P (1)	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+	Baa1	BBB+	BBB+	A2	A+
Senior secured	n/a	n/a	n/a	A	Aa3	AA-
Ratings outlook	Positive	Stable	Positive	Positive	Stable	Stable

(1) During the third quarter of 2015, S&P revised both AGL Resources' and Nicor Gas' ratings outlooks to positive from stable and Fitch revised AGL Resources' outlook to positive.
(2) Credit ratings are for AGL Capital, whose obligations are fully and unconditionally guaranteed by AGL Resources.
(3) Moody's downgraded AGL Capital's senior unsecured rating to Baa1 from A3 during the third quarter of 2015.

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; and
- 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.

We were in compliance with all of our debt provisions and covenants, both financial and non-financial, as of December 31, 2015 and 2014. For additional information on our default provisions, see Note 9 to our consolidated financial statements under Item 8 herein.

Cash Flows

We prepare our Consolidated Statements of Cash Flows using the indirect method, under which 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, non-cash impairment charges, gains or losses on the sale of assets and changes on the Consolidated Balance Sheets for working capital during the period. The following table provides a summary of our operating, investing and financing cash flows for the last three years.

In millions	2015	2014	2013
Net cash provided by (used in) (1):			
Operating activities	$1,381	$655	$971
Investing activities	(1,027)	(505)	(876)
Financing activities	(366)	(224)	(121)
Net decrease in cash and cash equivalents - continuing operations	(12)	(51)	(26)

Net decrease in cash and cash equivalents - discontinued operations	—	(23)	—
Cash and cash equivalents (including held for sale) at beginning of period	31	105	131
Cash and cash equivalents (including held for sale) at end of period	19	31	105
Less cash and cash equivalents held for sale at end of period	—	—	24
Cash and cash equivalents (excluding held for sale) at end of period	$19	$31	$81

(1) Amounts for 2014 and 2013 include activity for discontinued operations.

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Cash Flow from Operating Activities 2015 compared to 2014 Our net cash flow provided by operating activities in 2015 was $1.4 billion, an increase of $726 million, or 111%, from 2014. The increase was primarily related to (i) higher working capital needs during the prior year that was driven by higher natural gas prices and volumes delivered as well as the timing of recoveries of related gas costs from customers, (ii) cash provided by derivative financial instrument assets and liabilities primarily as a result of the decrease in forward NYMEX prices year-over-year and (iii) a 2014 tax refund of $150 million received in January 2015 related to the prior year extension of bonus depreciation late in 2014 (the 2015 tax refund related to the extension of bonus depreciation in late 2015 is expected in early 2016). These increases were partially offset by (i) lower earnings year-over-year largely attributable to warmer weather than experienced in 2014, and (ii) energy marketing receivables and payables, due to less cash received in 2015 from the prior year.

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 2014 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.

Cash Flow from Investing Activities Our net cash flow used in investing activities in 2015 increased $522 million, or 103%, from 2014, primarily as a result of increased infrastructure investment, primarily relating to Nicor Gas' Investing in Illinois program, combined with increased spending for other rate-based investments at distribution operations. Additionally, the variance was driven by the $225 million proceeds from the sale of Tropical Shipping during the third quarter of 2014. Our estimated PP&E expenditures for 2016 and our actual PP&E expenditures incurred in 2015, 2014 and 2013 are presented in the following table.

In millions	Description	2016	2015	2014	2013
Distribution business	New construction and infrastructure improvements	$486	$440	$475	$421
Regulatory infrastructure programs (1)	Programs that update or expand our distribution systems to improve system reliability	531	461	180	226
Storage, pipelines and LNG facilities	Underground natural gas storage facilities, pipeline infrastructure and LNG production and transportation	143	27	15	8
Other	Primarily includes information technology and building and leasehold improvements	116	99	99	76
Total		$1,276	$1,027	$769	$731

(1) Includes Investing in Illinois at Nicor Gas, STRIDE at Atlanta Gas Light, SAVE at Virginia Natural Gas, AIR at Elizabethtown Gas and SAFE at Florida City Gas.

The 2015 increase in PP&E expenditures of $258 million, or 34%, was due to increased spending of $281 million related to infrastructure improvements on our Investing in Illinois program. This was partially offset by decreased spending related to our new construction projects.

Our PP&E expenditures were $769 million for the year ended December 31, 2014, compared to $731 million for the same period in 2013. The increase 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 estimated expenditures for 2016 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 make adjustments to our discretionary expenditures as necessary based upon these factors.

Cash Flow from Financing Activities Our net cash flow used in financing activities in 2015 increased $142 million, or 63%, from 2014 primarily as a result of the net repayments of our commercial paper during 2015, partially offset by the excess of proceeds from our issuance of senior notes in the fourth quarter of 2015 over the senior notes that matured in the first quarter of 2015. For more information on our financing activities, see "Short-term Debt" and "Long-term Debt" within Item 7 under the caption “Liquidity and Capital Resources.”

Noncontrolling Interest We recorded cash distributions for SouthStar’s dividends to Piedmont of $18 million in 2015, $17 million in 2014 and $17 million in 2013 as financing activities on our Consolidated Statements of Cash Flows.

Dividends on Common Stock Our common stock dividend payments were $244 million in 2015, $233 million in 2014 and $222 million in 2013. The increases were primarily due to the annual dividend increase of $0.08 per share in each of 2015 and 2014.

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Off-balance sheet arrangements We have certain guarantees, as further described in Note 12 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 Balance Sheets. See Note 4 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 commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected future contractual obligation payments and commitments and contingencies as of December 31, 2015.

In millions	Total	2016	2017	2018	2019	2020	2021 & thereafter
Recorded contractual obligations:							
Long-term debt	$3,756	$545	$22	$155	$350	$—	$2,684
Short-term debt	1,010	1,010	—	—	—	—	—
Environmental remediation liabilities (1)	431	67	79	70	61	52	102
Total	$5,197	$1,622	$101	$225	$411	$52	$2,786
Unrecorded contractual obligations and commitments (2) (7):							
Pipeline charges, storage capacity and gas supply (3)	$5,007	$795	$536	$392	$370	$318	$2,596
Interest charges (4)	2,418	181	158	156	151	133	1,639
Operating leases (5)	159	31	26	18	16	15	53
Asset management agreements (6)	28	11	9	6	2	—	—
Standby letters of credit, performance/surety bonds (7)	73	73	—	—	—	—	—
Other	5	3	1	1	—	—	—
Total	$7,690	$1,094	$730	$573	$539	$466	$4,288

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

(2) In accordance with GAAP, these items are not reflected on our Consolidated Balance Sheets.

(3) 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 37 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2015, and is valued at $76 million. As we do for certain of our affiliates, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(4) Floating rate interest charges are calculated based on the interest rate as of December 31, 2015 and the maturity date of the underlying debt instrument. As of December 31, 2015, we have $49 million of accrued interest on our Consolidated Balance Sheets that will be paid in 2016.

(5) 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.

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

(7)

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

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

Pension and welfare obligations. Generally, our pension plan 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 agencies. The state regulatory agencies 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 $125 million as of December 31, 2015 and $122 million as of December 31, 2014. In Illinois, all accrued retirement plan expenses are recovered through base rates. See Note 7 to our consolidated financial statements under Item 8 herein for additional information about our pension and welfare plans.

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In both 2015 and 2014, no contributions were required to our qualified pension plan. Based on the estimated funded status of the AGL Plan, we do not expect any required contribution to the plan in 2016. We may, at times, elect to contribute additional amounts to the AGL 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 3 to our consolidated financial statements under Item 8 herein.

Accounting for Rate-Regulated Subsidiaries

At December 31, 2015, our regulatory assets were $738 million and regulatory liabilities were $1.7 billion. At December 31, 2014, our regulatory assets were $714 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 GAAP. Accordingly, the financial results of these operations reflect the effects of the ratemaking and accounting practices and policies of the various regulatory agencies 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, 2015 would result in 5% and 16% decreases in total assets and total liabilities, respectively. For more information on our regulated assets and liabilities, see Note 3 and Note 4 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 annually 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 qualitative step 0 assessment is made to determine whether it is more likely than not that the fair value of each reporting unit is less than its carrying amount before applying the two-step, quantitative goodwill impairment test. If we elect to perform the qualitative assessment, we evaluate relevant events and circumstances, including but not limited to, macroeconomic conditions, industry and market conditions, cost factors, financial performance, entity specific events and events specific to each reporting unit. If we determine that it is more likely than not that the fair value of a reporting unit is less than its carrying amount we perform the two-step goodwill impairment test.

Step 1 of the two-step goodwill impairment test compares the fair value of the reporting unit to its carrying value. If the result of our step 1 test reveals that the estimated fair value is below its carrying value we proceed with step 2. Step 2 of the goodwill impairment test compares the implied fair value of goodwill, which is calculated as the residual amount from the reporting unit's overall fair value after assigning fair values to its assets and liabilities under a hypothetical purchase price allocation as if the reporting unit had been acquired in a business combination, to its carrying value. Based on the result of the step 2 test, we record a goodwill impairment charge for any excess of carrying value over the implied fair value of goodwill.

While preparing our third quarter 2015 financial statements, and in connection with our 2016 annual budget process, we assessed various market factors and projections prepared by both internal and external sources related to subscription rates for contracting capacity at our storage facilities as well as the profitability of our storage and fuels reporting unit. Based on this assessment, we concluded that a decline in projected storage subscription rates as well as a reduction in the near-term projection of the reporting unit's profitability required us to perform an interim goodwill impairment test as of September 30, 2015.

The two-step goodwill impairment test for our storage and fuels reporting unit within the midstream operations segment resulted in a non-cash impairment charge of the full $14 million ($9 million, net of tax) of goodwill.

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For our 2015 annual impairment test for all other reporting units, we performed the qualitative step 0 assessment described above and determined that it is more likely than not that the fair value of our reporting units exceed their carrying amounts, and therefore, no quantitative analysis was required. The amounts of goodwill as of December 31, 2015 and 2014 are provided below.

In millions	Distribution operations	Retail operations	Midstream operations	Consolidated
Goodwill - December 31, 2014	$1,640	$173	$14	$1,827
Impairment	—	—	(14)	(14)
Goodwill - December 31, 2015	$1,640	$173	$—	$1,813

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.

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. As a result of this provision, the seller paid us $5 million in January 2015, which is reflected as a reduction to our intangible assets on our Consolidated Balance Sheet as of December 31, 2015 and reduced 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 Balance Sheets 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 on the Consolidated Statements of Income in the case of a fair value hedge, or to record the gains and losses in OCI on the Consolidated Balance Sheets 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 agencies, 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 and to a lesser extent we hedge against warmer-than-normal weather and interest rates. 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.

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Additionally, as required by the authoritative guidance, we 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 creditworthiness 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.

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 3 and Note 6 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 our estimates can be, and often are, revised depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure. Changes in our 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 12 to our consolidated financial statements under Item 8 herein.

Pension and Welfare Plans

Our pension and welfare plans costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates. We review the estimates and assumptions underlying our pension and welfare plan costs and liabilities on an annual basis 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:

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

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 plans 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 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 Plan. The excess, if any, is amortized over the average remaining service period of active employees.

In the fourth quarter of 2015, we changed the method we use to estimate the net periodic benefit cost for our pension and welfare plans. Historically, we estimated the net periodic benefit costs by applying a single weighted-average discount rate derived from a yield curve of 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. We have elected to use a full yield curve approach in the estimation of the benefit cost by applying the specific spot rates along the yield curve of 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. We have made this change to improve the correlation between projected benefit cash flows and the corresponding yield curve spot rates and to provide a more precise measurement of costs. This change does not affect the measurement of our total benefit obligations as the change in the net periodic benefit costs is completely offset in the actuarial (gain) loss reported.

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We have accounted for this change as a change in estimate and, accordingly, have accounted for it prospectively starting in 2016. The reduction in net periodic benefit cost for 2016 associated with this change in estimate is approximately $7 million.

During 2015, we recorded net periodic benefit costs of $48 million (pre-capitalization) related to our defined pension and welfare benefit plans. We estimate that in 2016, we will record net periodic pension and welfare benefit costs in the range of $32 million to $36 million (pre-capitalization), a $16 million to $12 million decrease compared to 2015. In calculating our estimated expenses for 2016, our actuarial consultant assumed the following expected return on plan assets and discount rates:

	Pension plans		Welfare plans	
Discount rate - service cost	4.6	%	4.4	%
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%	(157) / 193	(14) / 15

See Note 5 and Note 7 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 expenses 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 from 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.

Deferred tax assets are evaluated for future realization and reduced by a valuation allowance to the extent we believe they will not be realized. We consider many factors when assessing the likelihood of future realization of our deferred tax assets, including our expectations of future taxable income and capital gains by taxing jurisdiction, the carry-forward periods available to us for tax reporting purposes, and other relevant factors. We allocate our valuation allowance to current and long-term deferred tax assets on a pro-rata basis. We had a $19 million valuation allowance on $312 million of deferred tax assets ($249 million long-term and $63 million current) as of December 31, 2015, reflecting the expectation that a majority of these assets will be realized. Our gross long-term deferred tax liability totaled $2.1 billion at December 31, 2015. See Note 13 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 uncertainty in income taxes 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 uncertainty in income taxes in interest expense, and penalties in operating expense on the Consolidated Statements of Income. As of December 31, 2015, we did not have a liability recorded for payment of interest and penalties associated with uncertainty in income taxes.

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Accounting Developments

See “Accounting Developments” in Note 3 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 and credit. Natural gas price risk results from changes in the fair value of natural gas. Interest rate risk is caused by fluctuations in interest rates related to our portfolio of debt 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 in wholesale services and at Atlanta Gas Light in distribution operations. We generally 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, which prohibits the use of derivatives for speculative purposes.

Our Risk Management Committee 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 Risk Management Committee 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 Risk Management Committee 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 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; therefore, they 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 the 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 3 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, 2015 and 2014.

	Derivative instruments average values at December 31, [1]	
In millions	2015	2014

Asset	$187	$152
Liability	88	101

(1) Excludes cash collateral amounts.

	Derivative instruments fair values netted with cash collateral at December 31,	
In millions	2015	2014
Asset	$218	$287
Liability	46	93

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

In millions	2015	2014	2013
Net fair value of derivative instruments outstanding at beginning of period	$61	$(82)	$36
Derivative instruments realized or otherwise settled during period	(17)	38	(62)
Change in net fair value of derivative instruments	32	105	(56)
Net fair value of derivative instruments outstanding at end of period	76	61	(82)
Netting of cash collateral	96	133	121
Cash collateral and net fair value of derivative instruments outstanding at end of period [1]	$172	$194	$39

(1) Net fair value of derivative instruments outstanding includes $10 million premium and associated intrinsic value at December 31, 2015, and $3 million at December 31, 2014 and 2013 associated with weather derivatives.

The sources of our net fair value at December 31, 2015 are as follows.

In millions	Prices actively quoted (Level 1) [1]	Significant other observable inputs (Level 2) [2]
Mature 2016	$8	$78
Mature 2017 – 2018	(13)	9
Mature 2019 and thereafter	(5)	(1)
Total derivative instruments [3]	$(10)	$86

(1) Valued using NYMEX futures prices.

(2) Valued using 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 VaR is the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability. Our 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 2014, resulting in our VaR to be at elevated levels during the prior year. 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 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 first quarter of 2014, 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, 2015, 2014 and 2013 were less than $0.1 million and wholesale services had the following VaRs.

In millions	2015	2014	2013
Period end	$2.4	$4.7	$4.7
12-month average	3.0	4.3	2.3
High	7.3	19.7	4.9
Low	1.6	1.8	1.2

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. Based on $1.3 billion of variable-rate debt outstanding at December 31, 2015, a 100 basis point change in market interest rates would have resulted in an increase in pre-tax interest expense of $13 million on an annualized basis.

We utilize interest rate swaps to help us achieve our desired mix of variable to fixed-rate debt. Our variable-rate debt target generally ranges from 20% to 45% of total debt. We also 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 3 and Note 6 to our consolidated financial statements under Item 8 herein.

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During the fourth quarter of 2014, senior notes totaling $120 million converted from a fixed interest rate to a LIBOR-based variable interest rate. Additionally, 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 our senior note issuance in the fourth quarter of 2015 and our anticipated issuances in 2016. We have designated the forward-starting interest rate swaps, which are settled on the respective debt issuance dates, as cash flow hedges. We settled $200 million of these interest rate swaps on November 18, 2015, in conjunction with our November 2015 issuance of $250 million in senior notes. The remaining $600 million of interest rate swaps are expected to be settled in 2016. We performed a qualitative assessment of effectiveness as of December 31, 2015 and concluded that the remaining hedges are highly effective.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk, as it bills 14 certificated and active Marketers in Georgia for its services. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak 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. 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 2015, the four largest Marketers based on customer count accounted for 16% of our consolidated operating margin and 21% of distribution operations' operating margin.

Several factors are designed to mitigate our risks from the increased concentration of credit that has resulted from deregulation. In addition to the security support described above, Atlanta Gas Light bills intrastate delivery service to Marketers in advance rather than in arrears. We accept credit support in the form of cash deposits, letters of credit/surety bonds from acceptable issuers and corporate guarantees from investment-grade entities. On a monthly basis, the Risk Management Committee reviews 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 are 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 likely 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, 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 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 for payment or delivery 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, 2015, for agreements with such features, our distribution operations derivative instruments with liability fair values totaled $30 million, for which we had posted $13 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.

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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, 2015, our top 20 counterparties represented approximately 53%, or $196 million, of our total counterparty exposure and 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, respectively, and 1 being D or Default by S&P and Moody's, respectively. 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 provides credit risk information related to our third-party natural gas contracts receivable and payable positions as of December 31.

	Gross receivables		Gross payables	
In millions	2015	2014	2015	2014
Netting agreements in place:				
Counterparty is investment grade	$299	$482	$136	$276
Counterparty is non-investment grade	8	4	17	7
Counterparty has no external rating	133	263	265	494
No netting agreements in place:				
Counterparty is investment grade	5	30	—	—
Amount recorded on Consolidated Balance Sheets	$445	$779	$418	$777

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 $2 million at December 31, 2015, which would not have had a material impact on our consolidated results of operations, cash flows or financial condition.

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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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 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, 2015, 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, 2016

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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, 2015, 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, 2015.

The effectiveness of our internal control over financial reporting as of December 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 11, 2016

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

/s/ Elizabeth W. Reese
Elizabeth W. Reese
Executive Vice President and Chief Financial Officer

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - ASSETS

	As of December 31,	
In millions	2015	2014
Current assets		
Cash and cash equivalents	$19	$31
Short-term investments	8	8
Receivables		
Energy marketing	445	779
Natural gas	266	391
Unbilled revenues	140	256
Other	110	150
Less allowance for uncollectible accounts	29	35
Total receivables, net	932	1,541
Inventories		
Natural gas	622	694
Other	29	22
Total inventories	651	716
Prepaid expenses	218	223
Derivative instruments	206	245
Regulatory assets	68	83
Other	13	39
Total current assets	2,115	2,886
Long-term assets and other deferred debits		
Property, plant and equipment	12,566	11,552
Less accumulated depreciation	2,775	2,462
Property, plant and equipment, net	9,791	9,090
Goodwill	1,813	1,827
Regulatory assets	670	631
Intangible assets	109	125
Long-term investments	103	105
Pension assets	78	97
Derivative instruments	12	42
Other	63	85
Total long-term assets and other deferred debits	12,639	12,002
Total assets	$14,754	$14,888

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED BALANCE SHEETS - LIABILITIES AND EQUITY

	As of December 31,	
In millions, except share and per share amounts	2015	2014
Current liabilities		
Short-term debt	$1,010	$1,175
Current portion of long-term debt	545	200
Energy marketing trade payables	418	777
Other accounts payable – trade	255	312
Customer deposits and credit balances	165	125
Regulatory liabilities	134	112
Accrued wages and salaries	92	97
Accrued environmental remediation liabilities	67	87
Accrued taxes	59	79
Accrued interest	49	53
Derivative instruments	44	88
Current deferred income taxes	31	2
Other	131	112
Total current liabilities	3,000	3,219
Long-term liabilities and other deferred credits		
Long-term debt	3,275	3,581
Accumulated deferred income taxes	1,912	1,724
Regulatory liabilities	1,611	1,601
Accrued pension and retiree welfare benefits	515	525
Accrued environmental remediation liabilities	364	327
Other	102	83
Total long-term liabilities and other deferred credits	7,779	7,841
Total liabilities and other deferred credits	10,779	11,060
Commitments, guarantees and contingencies (see Note 12)		
Equity		
Common stock, $5 par value; 750,000,000 shares authorized; outstanding: 120,376,721 shares at December 31, 2015 and 119,647,149 shares at December 31, 2014	603	599
Additional paid-in capital	2,099	2,087
Retained earnings	1,421	1,312
Accumulated other comprehensive loss	(186)	(206)
Treasury shares, at cost: 216,523 shares at December 31, 2015 and 2014	(8)	(8)
Total common shareholders’ equity	3,929	3,784
Noncontrolling interest	46	44
Total equity	3,975	3,828
Total liabilities and equity	$14,754	$14,888

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBISIDIARIES
CONSOLIDATED STATEMENTS OF INCOME

	Years ended December 31,		
In millions, except per share amounts	2015	2014	2013
Operating revenues (includes revenue taxes of $103 for 2015, $133 for 2014 and $112 for 2013, respectively)	$3,941	$5,385	$4,209
Operating expenses			
Cost of goods sold	1,645	2,765	2,110
Operation and maintenance	914	939	887
Depreciation and amortization	397	380	397
Taxes other than income taxes	181	208	187
Merger-related expenses	44	—	—
Goodwill impairment	14	—	—
Total operating expenses	3,195	4,292	3,581
Gain on disposition of assets	—	2	11
Operating income	746	1,095	639
Other income	13	14	16
Interest expense, net	(173)	(179)	(170)
Income before income taxes	586	930	485
Income tax expense	213	350	177
Income from continuing operations	373	580	308
(Loss) income from discontinued operations, net of tax	—	(80)	5
Net income	373	500	313
Less net income attributable to the noncontrolling interest	20	18	18
Net income attributable to AGL Resources	$353	$482	$295
Net income attributable to AGL Resources			
Income from continuing operations attributable to AGL Resources	$353	$562	$290
(Loss) income from discontinued operations, net of tax	—	(80)	5
Net income attributable to AGL Resources	$353	$482	$295
Per common share information			
Basic earnings (loss) per common share			
Continuing operations	$2.95	$4.73	$2.46
Discontinued operations	—	(0.67)	0.04
Basic earnings per common share attributable to AGL Resources common shareholders	$2.95	$4.06	$2.50
Diluted earnings (loss) per common share			
Continuing operations	$2.94	$4.71	$2.45
Discontinued operations	—	(0.67)	0.04
Diluted earnings per common share attributable to AGL Resources common shareholders	$2.94	$4.04	$2.49
Cash dividends declared per common share	$2.04	$1.96	$1.88
Weighted average number of common shares outstanding			
Basic	119.6	118.8	117.9
Diluted	119.9	119.2	118.3

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	2015	2014	2013
Net income	$373	$500	$313
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 $0, $48 and $46)	—	(71)	66
Reclassification of actuarial loss to net benefit cost (net of income tax of $9, $6 and $10)	14	9	15
Reclassification of prior service cost to net benefit cost (net of income tax of $0, $1 and $2)	(2)	(1)	(3)
Retirement benefit plans, net	12	(63)	78
Cash flow hedges, net of tax			
Net derivative instrument (loss) gain arising during the period (net of income tax of $3, $2 and $1)	—	(6)	1
Reclassification of realized derivative loss (gain) to net income (net of income tax of $1, $2 and $1)	8	(3)	3
Cash flow hedges, net	8	(9)	4
Other comprehensive income (loss), net of tax	20	(72)	82
Comprehensive income	393	428	395
Less comprehensive income attributable to noncontrolling interest	20	16	18
Comprehensive income attributable to AGL Resources	$373	$412	$377

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF EQUITY

In millions, except per share amounts	AGL Resources Inc. Shareholders Common stock Shares	Amount	Additional paid-in capital	Retained earnings	Accumulated other comprehensive loss	Treasury shares	Noncontrolling interest	Total
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)
Distribution to noncontrolling interest	—	—	—	—	—	—	(17)	(17)
Contribution from noncontrolling interest	—	—	—	—	—	—	22	22
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 loss	—	—	—	—	(70)	—	(2)	(72)
Dividends on common stock ($1.96 per share)	—	—	—	(233)	—	—	—	(233)
Distribution to noncontrolling interest	—	—	—	—	—	—	(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
Net income	—	—	—	353	—	—	20	373
Other comprehensive income	—	—	—	—	20	—	—	20
Dividends on common stock ($2.04 per share)	—	—	—	(244)	—	—	—	(244)
	—	—	—	—	—	—	(18)	(18)

Distribution to noncontrolling interest								
Stock granted, share-based compensation, net of forfeitures	—	—	(14)	—	—	—	—	(14)
Stock issued, dividend reinvestment plan	0.3	1	11	—	—	—	—	12
Stock issued, share-based compensation, net of forfeitures	0.5	3	13	—	—	—	—	16
Stock-based compensation expense, net of tax	—	—	2	—	—	—	—	2
As of December 31, 2015	120.4	$603	$ 2,099	$ 1,421	$ (186)	$(8)	$ 46	$3,975

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years ended December 31,		
In millions	2015	2014	2013
Cash flows from operating activities			
Net income	$373	$500	$313
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	397	380	397
Deferred income taxes	211	201	(16)
Change in derivative instrument assets and liabilities	22	(155)	66
Goodwill impairment	14	—	—
Gain on disposition of assets	—	(2)	(11)
Loss (income) from discontinued operations, net of tax	—	80	(5)
Changes in certain assets and liabilities			
Receivables, other than energy marketing	275	(55)	(74)
Inventories	65	(58)	41
Prepaid and miscellaneous taxes	3	(244)	103
Accrued/deferred natural gas costs	(6)	(67)	2
Accrued expenses	(9)	32	39
Energy marketing receivables and trade payables, net	(25)	113	(54)
Trade payables, other than energy marketing	(75)	(81)	89
Other, net	136	21	70
Net cash flow (used in) provided by operating activities of discontinued operations	—	(10)	11
Net cash flow provided by operating activities	1,381	655	971
Cash flows from investing activities			
Expenditures for property, plant and equipment	(1,027)	(769)	(731)
Disposition of assets	—	230	12
Acquisitions of assets	—	—	(154)
Other, net	—	47	8
Net cash flow used in investing activities of discontinued operations	—	(13)	(11)
Net cash flow used in investing activities	(1,027)	(505)	(876)
Cash flows from financing activities			
Issuance of senior notes	248	—	494
Benefit, dividend reinvestment and stock purchase plan	13	22	33
Distribution to noncontrolling interest	(18)	(17)	(17)
Net (repayments) issuances of commercial paper	(165)	4	(206)
Payment of senior notes	(200)	—	(225)
Dividends paid on common shares	(244)	(233)	(222)
Contribution from noncontrolling interest	—	—	22
Net cash flow used in financing activities	(366)	(224)	(121)
Net decrease in cash and cash equivalents - continuing operations	(12)	(51)	(26)
Net decrease in cash and cash equivalents - discontinued operations	—	(23)	—
Cash and cash equivalents (including held for sale) at beginning of period	31	105	131
Cash and cash equivalents (including held for sale) at end of period	19	31	105
Less cash and cash equivalents held for sale at end of period	—	—	24
Cash and cash equivalents (excluding held for sale) at end of period	$19	$31	$81

Cash paid (received) during the period for			
Interest	$181	$187	$175
Income taxes	(26)	422	120
Non cash financing transaction			
Refinancing of gas facility revenue bonds	$—	$—	$200

See Notes to Consolidated Financial Statements.

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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, 2015 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 and the accounts of our VIE for which we are the primary beneficiary. For unconsolidated entities that we do not control, we use the equity method of accounting and our proportionate share of income or loss is recorded on our Consolidated Statements of Income. See Note 11 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 September 2014, we closed on the sale of Tropical Shipping, which operated within our former cargo shipping segment and whose financial results for the years ended December 31, 2014 and 2013 are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in the following notes, unless otherwise indicated, exclude discontinued operations. See Note 15 for additional information on the sale of Tropical Shipping.
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 - Proposed Merger with Southern Company
On August 23, 2015, we entered into the Merger Agreement with Southern Company and a new wholly owned subsidiary of Southern Company (Merger Sub), providing for the merger of Merger Sub with and into AGL Resources, with us surviving as a wholly owned subsidiary of Southern Company. At the effective time of the merger, which is expected to occur in the second half of 2016, each share of our common stock, other than certain excluded shares, will convert into the right to receive $66 in cash, without interest, less any applicable withholding taxes. Following the effective time of the merger, we will become a wholly owned, direct subsidiary of Southern Company.
Completion of the merger remains subject to various closing conditions, including, among others (i) the receipt of required regulatory approvals from the Federal Communications Commission, California Public Utilities Commission, Georgia Commission, Illinois Commission, Maryland Commission, New Jersey BPU and Virginia Commission, and such approvals having become final orders and (iii) the absence of a judgment, order, decision, injunction, ruling or other finding or agency requirement of a governmental entity prohibiting the closing of the merger.
At a special meeting of shareholders held on November 19, 2015, the proposed merger was approved by our shareholders. The waiting period under the Hart-Scott-Rodino Act expired on December 4, 2015. We and Southern Company have made joint filings seeking regulatory approval of the proposed merger with all of the required state regulatory agencies.
The Merger Agreement contains certain termination rights for each party. In addition, the Merger Agreement, in certain circumstances, provides for the payment by AGL Resources of a $201 million termination fee to Southern Company and, in certain circumstances, provides for the reimbursement of expenses up to $5 million upon termination of the Merger Agreement (which reimbursement would reduce on a dollar-for-dollar basis any termination fee subsequently paid by us). As of December 31, 2015 we had recorded no liability for termination fees.
In connection with this transaction, we recorded merger-related costs in the accompanying Consolidated Statements of Income of $44 million ($26 million, net of tax) for the year ended December 31, 2015. The transaction costs incurred to date are comprised of $24 million of additional stock-based compensation expense associated with the proposed merger as we remeasured our performance share unit awards based upon the increase in trading price of our common stock since the announcement of the Merger Agreement, $16 million of expenses associated with financial advisory, legal and other merger-related costs and $4 million of board of directors stock-based compensation related to the aforementioned increase in the trading price of our common stock. We treated these costs as tax deductible since the requisite closing conditions to the merger have not yet been satisfied. Once the merger is closed, we will evaluate the

tax deductibility of these costs and reflect any non-deductible amounts in the effective tax rate.
Additionally, subsequent to the announcement of the merger, AGL Resources and each member of the Board were named as defendants in four purported shareholder class action lawsuits relating to the merger, which were dismissed during the first quarter of 2016.

Note 3 - 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 with original maturities of three months or less.

Energy Marketing Receivables and Payables

Wholesale services provides services to retail marketers, wholesale marketers, utility companies 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 Balance Sheets 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, 2015 and 2014, 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 its 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, 2015, our top 20 counterparties represented 53%, or $196 million, of our total counterparty exposure and had a weighted average S&P equivalent rating of A-.

We have established credit policies to determine and monitor the creditworthiness of counterparties, including requirements to post 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 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 4 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 14 Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the non-peak 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.

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Inventories
For our regulated utilities, except Nicor Gas, 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 to Marketers the majority of the pipeline storage services that it has under contract, along with a corresponding amount of inventory. Atlanta Gas Light retains and manages a portion of its pipeline storage assets and related natural gas inventories for system balancing and to serve system demand.
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, 2015, the Nicor Gas LIFO inventory balance was $145 million. Based on the average cost of gas purchased in December 2015, the estimated replacement cost of Nicor Gas' inventory at December 31, 2015 was $201 million, which exceeded the LIFO cost by $56 million. During 2015, we did not liquidate any of our LIFO-based inventory.
Our retail operations, wholesale services and midstream operations segments carry inventory at LOCOM, 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 table, for any declines considered to be other than temporary, we recorded LOCOM adjustments to cost of goods sold to reduce the value of our natural gas inventories to market value.

In millions	2015	2014	2013
Retail operations	$3	$4	$1
Wholesale services (1)	19	73	8
Other	1	—	—
Total	$23	$77	$9

(1) The increase in 2014 was due to a significant decline in natural gas prices in December 2014.
Operational issues at a third-party storage facility during 2015 caused 5 Bcf of our inventory at wholesale services to be inaccessible. These operational issues at this facility have been resolved, and we began withdrawing the inventory in the fourth quarter of 2015. Our capacity contract with the facility expires at the end of the first quarter of 2016.
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 and identified a lower amount of working gas capacity due to naturally occurring shrinkage of the storage cavern. Further, based on the lower capacity and an analysis of the volume of natural gas stored in the facility, we recorded $10 million in additional natural gas costs for the year ended December 31, 2014 to true-up the amount of retained fuel at this facility. 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 agencies.
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 instruments. The carrying values of receivables, short and long-term investments, accounts payable, short-term debt, other current assets and liabilities, and accrued interest approximate their respective fair value. Our nonfinancial assets and liabilities include pension and welfare benefits. See Note 5 for additional fair value disclosures.

As defined in the authoritative guidance related to fair value measurements and disclosures, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in valuing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements to utilize the best available information. Accordingly, we use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observance of those inputs. The guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy defined by the guidance are as follows:

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

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

Level 3 Pricing inputs include significant unobservable inputs that may be used with internally developed methodologies to determine management’s best estimate of fair value from the perspective of market participants. Level 3 instruments include those that may be more structured or otherwise tailored to customers’ needs. Our Level 3 assets, liabilities and any applicable transfers are primarily related to our pension and welfare benefit plan assets as described in Note 5 and Note 7. 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, which 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 5 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 Balance Sheets. 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 5 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 warmer-than-normal 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 6 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 or 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 on our Consolidated Balance Sheets. 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.

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For our 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. These weather derivatives are 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 on 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 on 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. 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 on our Consolidated Balance Sheets, with changes in fair value recorded in operating revenues on 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 on 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. See Note 5 for fair value disclosure.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2015 and 2014 is provided in the following table.

In millions	2015	2014
Transportation and distribution	$9,912	$9,105
Storage facilities	1,255	1,202
Other	985	919
Construction work in progress	414	326
PP&E, gross	12,566	11,552
Less accumulated depreciation	2,775	2,462

PP&E, net	$9,791	$9,090

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.

Glossary

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We do not recognize any gains or losses on depreciable utility property that is retired or otherwise disposed, as required under the composite depreciation method. Such gains or losses are ultimately refunded to, or recovered from, customers through future rate adjustments. Our natural gas utilities also hold property, primarily land, that 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, which is depreciated over the life of the storage facility.

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. At December 31, 2015, our 50% share of construction costs was $33 million and is reflected in construction work in process on our Consolidated Balance Sheets.

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.

	2015		2014		2013	
Atlanta Gas Light (1)	2.4	%	2.3	%	2.6	%
Chattanooga Gas (1)	2.5		2.5		2.5	
Elizabethtown Gas (2)	2.4		2.5		2.4	
Elkton Gas (2)	2.7		2.8		2.4	
Florida City Gas (2)	3.9		3.9		3.8	
Nicor Gas (2) (3)	3.1		3.1		3.1	
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

AFUDC 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. 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 on our Consolidated Balance Sheets. 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.

	2015	2014	2013
Atlanta Gas Light	8.10 %	8.10 %	8.10 %
Nicor Gas (1)	0.82 %	0.24 %	0.31 %
Chattanooga Gas	7.41 %	7.41 %	7.41 %
Elizabethtown Gas (1)	1.69 %	0.44 %	0.41 %
AFUDC (in millions) (2)	$6	$7	$18

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

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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, 2015 and 2014 principally for our storage facilities. For our distribution PP&E, we cannot reasonably estimate the fair value of this obligation because we have determined that we have insufficient internal or industry information to reasonably estimate the potential settlement dates or costs.
Impairment of Assets
Our goodwill is not amortized, but is subject to an annual impairment test. Our other long-lived assets, including our finite-lived intangible assets, require an impairment review when events or circumstances indicate that the carrying amount may not be recoverable. We base our evaluation of the recoverability of other long-lived assets on the presence of impairment indicators such as the future economic benefit of the assets, any historical or future profitability measurements and other external market conditions or factors.
Goodwill Our annual impairment test is performed at the reporting unit level during the fourth quarter of each year or more frequently if impairment indicators arise.
Our 2014 annual goodwill impairment test indicated that the estimated fair value of our storage and fuels reporting unit, that had $14 million of goodwill, within our midstream operations segment exceeded its carrying value by less than 5% and would be at risk of failing step 1 of the goodwill impairment test if a further decline in the estimated fair value were to occur. While preparing our third quarter 2015 financial statements, and in connection with our 2016 annual budget process, we assessed various market factors and projections prepared by both internal and external sources related to subscription rates for contracting capacity at our storage facilities as well as the profitability of our storage and fuels reporting unit. Based on this assessment, we concluded that a decline in projected storage subscription rates as well as a reduction in the near-term projection of the reporting unit's profitability required us to perform an interim goodwill impairment test as of September 30, 2015.
Step 1 of our interim goodwill impairment test compared the fair value of the reporting unit to its carrying value utilizing the income approach, under which the fair value was estimated based on the present value of estimated future cash flows discounted at an appropriate interest rate. The result of our step 1 test revealed that the estimated fair value of our storage and fuels reporting unit was below its carrying value.
Step 2 of this interim goodwill impairment test compared the implied fair value of goodwill in our storage and fuels reporting unit, which was calculated as the residual amount from the reporting unit's overall fair value after assigning fair values to its assets and liabilities under a hypothetical purchase price allocation as if the reporting unit had been acquired in a business combination, to its carrying value. Based on the result of our step 2 test, we recorded a non-cash impairment charge of the full $14 million ($9 million, net of tax) of goodwill.
For our 2015 annual goodwill impairment test of the remaining goodwill, we performed the qualitative step 0 assessment focusing on the following qualitative factors: macroeconomic conditions, industry and market conditions, cost factors, financial performance, entity specific events and events specific to each reporting unit. Our step 0 analysis concluded that it is more likely than not that the fair value of our reporting units that have goodwill exceeds their carrying amounts and a quantitative assessment was not required. The amounts of goodwill as of December 31, 2015 and 2014 are provided below.

In millions	Distribution operations	Retail operations	Midstream operations	Consolidated
Goodwill - December 31, 2014	$1,640	$173	$14	$1,827
Impairment	—	—	(14)	(14)
Goodwill - December 31, 2015	$1,640	$173	$—	$1,813

Long-Lived Assets We depreciate or amortize our long-lived assets and other intangible assets, which are all located in the U.S., 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 2015 or 2014; however, 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.

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In millions	Weighted average amortization period (in years)	December 31, 2015 Gross	Accumulated amortization	Net	December 31, 2014 Gross	Accumulated amortization	Net
Customer relationships	13	$132	$(57)	$75	$130	$(42)	$88
Trade names	13	45	(11)	34	45	(8)	37
Total		$177	$(68)	$109	$175	$(50)	$125

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 $18 million in 2015, $20 million in 2014 and $18 million in 2013. Amortization expense for the next five years is expected to be as follows:

In millions	Amortization Expense
2016	$17
2017	15
2018	14
2019	12
2020	11

Accounting for Retirement Benefit Plans

We recognize the funded status of our plans as an asset or a liability on our Consolidated Balance Sheets, 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 7. In addition, we have elected to amortize gains and losses caused by actual experience that differ 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. 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 on our Consolidated Balance Sheets.

We have current and deferred income taxes on 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 for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities on our Consolidated Balance Sheets. 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 15 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 uncertainty in income taxes 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.

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Uncertainty in Income Taxes We recognize accrued interest related to uncertainty in income taxes in interest expense and penalties in operating expense on 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 on our Consolidated Balance Sheets. 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 on our Consolidated Statements of Income.
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 agencies 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 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 straight-fixed-variable 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 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 on 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 $101 million in 2015, $130 million in 2014 and $110 million in 2013.
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.

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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 on the Consolidated Balance Sheets and exclude from, or include on, 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 4.
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 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 12.
Other Income
Our other income is detailed in the following table. For more information on our equity investment income, see Note 11.

In millions	2015	2014	2013
Equity investment income	$6	$8	$3
AFUDC - equity	4	5	12
Other, net	3	1	1
Total other income	$13	$14	$16

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 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 Balance Sheets, we recognize Piedmont's share of SouthStar 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.
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 Balance Sheets, 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 11.

Earnings Per Common Share

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

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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 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)	2015	2014	2013
Income from continuing operations attributable to AGL Resources	$353	$562	$290
(Loss) income from discontinued operations, net of tax	—	(80)	5
Net income attributable to AGL Resources	$353	$482	$295
Denominator:			
Basic weighted average number of common shares outstanding (1)	119.6	118.8	117.9
Effect of dilutive securities	0.3	0.4	0.4
Diluted weighted average number of common shares outstanding (2)	119.9	119.2	118.3
Basic earnings (loss) per common share			
Continuing operations	$2.95	$4.73	$2.46
Discontinued operations	—	(0.67)	0.04
Basic earnings per common share attributable to AGL Resources	$2.95	$4.06	$2.50
Diluted earnings (loss) per common share			
Continuing operations	$2.94	$4.71	$2.45
Discontinued operations	—	(0.67)	0.04
Diluted earnings per common share attributable to AGL Resources	$2.94	$4.04	$2.49

(1) Daily weighted average shares outstanding.

(2) All outstanding stock options for whose effect would have been anti-dilutive were excluded from the computation of diluted earnings per common share.

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 and 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.

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to use judgment and make estimates 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 the accounting for 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

Accounting standards adopted in 2015

In April 2015, the FASB issued updated authoritative guidance related to debt issuance costs. The amendment modifies the presentation of unamortized debt issuance costs on our Consolidated Balance Sheets. Under the new guidance, we present such amounts as a direct deduction from the face amount of the debt, similar to unamortized debt discounts and premiums, rather than as an asset. Amortization of the debt issuance costs continues to be reported as interest expense on the Consolidated Statements of Income. While the guidance would have been effective for us beginning January 1, 2016, we elected to adopt its provisions effective April 1, 2015, and have applied its provisions to each prior period presented for comparative purposes. This new guidance resulted in an adjustment to the presentation of debt issuance costs primarily from other long-term assets to offset the related debt balances in long-term debt totaling $20 million and $21 million as of December 31, 2015 and 2014, respectively. The April 2015 guidance did not address the classification of debt issuance costs related to line-of-credit arrangements and, consequently, we continued to report such costs as assets subject to amortization over the term of the arrangement. In August 2015, the FASB issued clarifying guidance supporting the deferral and presentation of line-of-credit related debt issuance costs as an asset and subsequently amortizing these costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the arrangement.

Other newly issued accounting standards and updated authoritative guidance

In May 2014, the FASB issued updated 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. In July 2015, the FASB delayed the effective date by one year and the guidance will now be effective for us beginning January 1, 2018. Early adoption of the standard is permitted, but not before the original effective date of December 15, 2016. 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 a stock-based compensation performance target that could be achieved after the requisite service period. The guidance was issued to resolve diversity in practice. The new guidance was applied prospectively and became effective for us beginning January 1, 2016. We have determined that this new guidance will not have a material impact on our consolidated financial statements.

In February 2015, the FASB issued updated authoritative guidance related to the consolidation of other legal entities into our financial statements. The amendments modify aspects of the consolidation determination that could potentially impact us, including the analysis of limited partnerships and similar legal entities, fee arrangements, and related party relationships. The guidance became effective for us on January 1, 2016. We have determined that this new guidance will not have a material impact on our consolidated financial statements.

In April 2015, the FASB issued authoritative guidance related to the accounting for fees paid in connection with arrangements with cloud-based software providers. Under the new guidance, unless a software arrangement includes specific elements enabling customers to possess and operate software on platforms other than that offered by the cloud-based provider, the cost of such arrangements is to be accounted for as an operating expense of the period incurred. The new guidance was applied prospectively and became effective for us on January 1, 2016. We have determined that this new guidance will not have a material impact on our consolidated financial statements.

In May 2015, the FASB issued updated authoritative guidance to reduce the diversity in fair value measurements hierarchy disclosures. This amendment removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share. This guidance became effective for us on January 1, 2016. We have determined that this new guidance will not have a material impact on our consolidated financial statements.

In July 2015, the FASB issued updated authoritative guidance to simplify the measurement of certain inventories. Under the new guidance, inventories are required to be measured at the lower of cost and net realizable value, the latter representing the estimated selling price in the ordinary course of business, reduced by costs of completion, disposal, and transportation. Under current guidance, inventories are required to be measured at the lower of cost or market, but depending upon specific circumstances, market could refer to replacement cost, net realizable value, or net realizable value reduced by a normal profit margin. The amendments do not apply to inventories carried on a LIFO basis, which for us applies only to our Nicor Gas inventories. The guidance is to be applied prospectively, is effective for us beginning January 1, 2017, and early adoption is permitted. We are currently evaluating the potential impact of this new guidance.

In November 2015, the FASB issued updated authoritative guidance to the Balance Sheet Classification of Deferred Taxes, which requires companies to present deferred income tax assets and deferred income tax liabilities as noncurrent in a classified balance sheet instead of the current requirement to separate deferred income tax liabilities and assets into current and noncurrent amounts. The guidance is effective for us beginning January 1, 2017. Early application is permitted either prospectively or retrospectively. We have determined that this new guidance will not have a material impact on our consolidated financial statements.

In January 2016, the FASB issued updated authoritative guidance related to classification and measurement of Financial Instruments. The amendments modify the accounting and presentation for certain financial liabilities and equity investments not consolidated or reported using the equity method. The guidance is effective for us beginning January 1, 2019; limited early adoption is permitted. We are currently evaluating the potential impact of this new guidance.

Glossary

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Note 4 – Regulated Operations

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

In millions	2015	2014
Regulatory assets		
Recoverable ERC	$31	$49
Recoverable pension and retiree welfare benefit costs	12	12
Recoverable seasonal rates	10	10
Deferred natural gas costs	6	3
Other	9	9
Regulatory assets - current	68	83
Recoverable ERC	370	329
Recoverable pension and retiree welfare benefit costs	113	110
Recoverable regulatory infrastructure program costs	83	69
Long-term debt fair value adjustment	66	74
Other	38	49
Regulatory assets - long-term	670	631
Total regulatory assets	$738	$714
Regulatory liabilities		
Accumulated removal costs	$53	$25
Bad debt over collection	42	33
Accrued natural gas costs	24	27
Other	15	27
Regulatory liabilities - current	134	112
Accumulated removal costs	1,538	1,520
Regulatory income tax liability	27	34
Bad debt over collection	21	12
Unamortized investment tax credit	20	22
Other	5	13
Regulatory liabilities - long-term	1,611	1,601
Total regulatory liabilities	$1,745	$1,713

Base rates are designed to provide the opportunity to recover cost and earn 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 agency 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 agencies. 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.

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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 on our Consolidated Balance Sheets. 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 billable to our customers.

In millions	Atlanta Gas Light		Virginia Natural Gas	Elizabethtown Gas	Nicor Gas	Total
December 31, 2015	$103	(1)	$12	$4	$3	$122
December 31, 2014	113		12	2	—	127

(1) In October 2015, Atlanta Gas Light received an order from the Georgia Commission, which included a final determination of the true-up recovery related to the PRP. The order allows Atlanta Gas Light to recover $144 million of the $178 million of incurred and allowed costs that were deferred for future recovery. These deferred costs were originally requested in a February 2015 filing for a true-up of unrecovered revenue. See Note 12 for additional information on Atlanta Gas Light's global resolution of this and other matters that were previously raised before the Georgia Commission.

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.

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 former 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 accrued environmental remediation liabilities are estimates of future remediation costs for investigation and cleanup of our current and former operating sites that are contaminated. These estimates are determined using engineering-based estimates and 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 environmental remediation liabilities are not regulatory liabilities; however, the associated expenses are deferred as corresponding regulatory assets until the costs are recovered from customers. We primarily recover these deferred costs through three rate riders that authorize dollar-for-dollar recovery. We expect to collect $31 million in revenues over the next 12 months, which is reflected as a current regulatory asset. We recovered $40 million in 2015, $51 million in 2014 and $24 million in 2013 from our ERC rate riders. The following table provides additional information on the estimated costs to remediate our current and former operating sites as of December 31, 2015.

In millions

	# of sites	Probabilistic model cost estimates (1)	Engineering-based estimates (1)	Amount recorded	Expected costs over next 12 months	Cost recovery period
Illinois (2)	26	$200 - $457	$ 50	$250	$32	As incurred
New Jersey	6	115 - 195	7	122	18	7 years
Georgia and Florida	13	29 - 52	23	52	12	5 years
North Carolina (3)	1	n/a	7	7	5	No recovery
Total	46	$344 - $704	$ 87	$431	$67	

(1) The year-end ERC cost estimates were completed as of November 30, 2015. 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, two of which 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. 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 and there is no amount included within our regulatory assets. Changes in estimated costs are recognized in income during the period of change.

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In July 2014, we reached a settlement with an insurance company for environmental claims relating to potential contamination at several MGP sites in New Jersey and North Carolina. The terms of the settlement required the insurance company to pay us a total of $77 million in two installments. We received a $45 million installment in the third quarter of 2014 and the remaining $32 million was paid in the second quarter of 2015. The New Jersey BPU has approved the use of the insurance proceeds to reduce the ERC expenditures that otherwise would have been recovered from our customers in future periods. This reduces our recoverable ERC regulatory assets and has 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 Balance Sheets 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	2014	2015	2016	2017
2015	$63	$12	$51	$—	$—	$30	$21
2014	63	35	28	—	16	12	—
2013	63	21	42	25	17	—	—

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 on our Consolidated Balance Sheets. 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, for which we implemented rates under the program that became effective in March 2015. We filed the first annual update under the program with the Illinois Commission on April 1, 2015.

Atlanta Gas Light Our four-year STRIDE program was approved in December 2013 and 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 i-SRP is permitted to spend $445 million 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 spend $91 million to extend its pipeline facilities to serve customers in areas without pipeline access and create new economic development opportunities in Georgia.

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 included in the approval of our STRIDE programs, which authorized a phased-in approach to funding the programs through monthly rider surcharges that began in 2015 and will remain 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 on our Consolidated Balance Sheets. This allowed cost is primarily the equity return on the capital investment under the program.

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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 September 2015, Elizabethtown Gas filed the Safety, Modernization and Reliability Tariff (SMART) plan with the New Jersey BPU seeking approval to invest more than $1.1 billion to replace 630 miles of vintage cast iron, steel and copper pipeline, as well as 240 regulator stations. If approved, the program is expected to be completed by 2027. As currently proposed, costs incurred under the program would be recovered primarily through a rider surcharge over a period of 10 years.

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, the precursor to the accelerated infrastructure replacement 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 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 ENDURE, a program designed to improve our distribution system’s resiliency against coastal storms and floods. Under the proposed plan, Elizabethtown Gas invested $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 allowed Elizabethtown Gas to increase its base rates effective November 1, 2015 for investments made under the program. The program was completed in October 2015.

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.

In November 2015, Virginia Natural Gas filed with the Virginia Commission for approval of an extension to the SAVE program through 2021, requesting approval of $30 million in 2016 and $35 million in each of 2017 through 2021.

Florida City Gas The Florida Commission approved Florida City Gas' Safety, Access and Facility Enhancement program in September 2015. Under the program, Florida City Gas will spend approximately $10 million annually over a 10-year period on infrastructure relocation and enhancement projects. Costs incurred under the program will be recovered through a rate rider with annual rate adjustments and true-ups. In October 2015, Florida City Gas began spending under the program and plant in service associated with work in the fourth quarter of 2015 will be included in the calculation of rates beginning January 1, 2016.

energySMART In May 2014, the Illinois Commission approved Nicor Gas’ energySMART, 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 on our Consolidated Balance Sheets. 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 8 to 17 years, based on the remaining recovery periods as designated by the applicable state regulatory agencies. 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 5 - Fair Value Measurements

Retirement benefit plans assets

The assets of the AGL Resources Inc. Retirement Plan (AGL Plan) and the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Welfare Plan) were allocated 72% equity and 28% fixed income at December 31, 2015, and 70% equity, 29% fixed income and 1% cash at December 31, 2014 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, 2015											
	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	$—	$—	$4	—	%	$1	$—	$—	$1	1	%
Equity securities:												
U.S. large cap [2]	$75	$199	$—	$274	32	%	$—	$52	$—	$52	58	%
U.S. small cap [2]	57	24	—	81	9	%	—	—	—	—	—	
International companies [3]	—	125	—	125	15	%	—	15	—	15	17	%
Emerging markets [4]	—	28	—	28	3	%	—	—	—	—	—	
Total equity securities	$132	$376	$—	$508	59	%	$—	$67	$—	$67	75	%
Fixed income securities:												
Corporate bonds [5]	$—	$91	$—	$91	11	%	$—	$22	$—	$22	24	%
Other (or gov't/muni bonds)	—	151	—	151	18	%	—	—	—	—	—	
Total fixed income securities	$—	$242	$—	$242	29	%	$—	$22	$—	$22	24	%
Other types of investments:												
Global hedged equity [6]	$—	$—	$40	$40	5	%	$—	$—	$—	$—	—	
Absolute return [7]	—	—	42	42	5	%	—	—	—	—	—	
Private capital [8]	—	—	20	20	2	%	—	—	—	—	—	
Total other investments	$—	$—	$102	$102	12	%	$—	$—	$—	$—	—	
Total assets at fair value	$136	$618	$102	$856	100	%	$1	$89	$—	$90	100	%
% of fair value hierarchy	16 %	72 %	12 %	100 %			1 %	99 %	—	100 %		

	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 %	—	—	—	—	— %
Total other investments	$—	$—	$91	$91	10 %	$—	$—	$—	$—	— %
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 %	

(1) Includes $9 million at December 31, 2015 and $9 million at December 31, 2014 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.

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(3) Includes funds that invest primarily in foreign equity and equity-related securities.
(4) Includes funds that invest primarily in common stocks of emerging markets.
(5) Includes funds that invest primarily in investment grade debt and fixed income securities.
(6) Includes funds that invest in limited / general partnerships, managed accounts, and other investment entities issued by non-traditional firms or "hedge funds."
(7) Includes funds that invest primarily in investment vehicles and commodity pools as a "fund of funds."
(8) Includes funds that invest in private equity and small buyout funds, partnership investments, direct investments, secondary investments, directly / indirectly in real estate and may invest in equity securities of real estate related companies, real estate mortgage loans, and real estate mezzanine loans.

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

	Fair value measurements using significant unobservable inputs - Level 3 [1]			
In millions	Global hedged equity	Absolute return	Private capital	Total
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
Actual return on plan assets	(1)	—	3	2
Purchases	12	—	—	12
Sales	—	—	(3)	(3)
Balance at December 31, 2015	$40	$42	$20	$102

(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, net of counterparty offset and collateral, on a recurring basis on our Consolidated Balance Sheets as of December 31. See Note 6 for additional information on our derivative instruments.

	2015		2014	
In millions	Assets [1]	Liabilities	Assets [1]	Liabilities
Natural gas derivatives				
Quoted prices in active markets (Level 1)	$53	$(63)	$58	$(80)
Significant other observable inputs (Level 2)	122	(46)	174	(94)
Netting of cash collateral	33	63	52	81
Total carrying value [2]	$208	$(46)	$284	$(93)

(1) Balances of $10 million and $3 million at December 31, 2015 and 2014, respectively, 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) or 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	2015	2014
Long-term debt carrying amount [1]	$3,820	$3,781
Long-term debt fair value [2]	4,066	4,231

(1) The change in the December 31, 2014 balance is related to our adoption of new accounting guidance in 2015 that resulted in the reclassification of debt issuance costs from other long-term assets to offset the

related debt balances in long-term debt. See Note 9 for additional information.

(2) Fair value determined using Level 2 inputs.

Note 6 - 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

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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, 2015 and 2014, for agreements with such features, derivative instruments with liability fair values totaled $46 million and $93 million, respectively, for which we had posted no collateral to our counterparties as we exceed the minimum credit rating requirements. As of December 31, 2015, the maximum collateral that could have been required with these features was $2 million. For additional information on our credit-risk-related contingent features, see "Energy Marketing Receivables and Payables" in Note 3 herein. Our derivative instrument activities are included within operating cash flows as an increase (decrease) to net income of $22 million, $(155) million and $66 million for the periods ended December 31, 2015, 2014 and 2013, 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	Balance Sheets	Income Statements
	Derivative carried at fair value	Ineffective portion of the gain or loss realized and unrealized on the derivative instrument is recognized in earnings
Cash flow hedge	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
	Derivative carried at fair value	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
Fair value hedge	Changes in fair value of the hedged item are recorded as adjustments to the carrying amount of the hedged item	
	Derivative carried at fair value	Gains or losses realized and unrealized on the derivative instrument are recognized in earnings
Not designated as hedges	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 the 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

Our derivative instruments are 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 natural gas contracts outstanding in the following quantities:

In Bcf [1]	2015 [2]	2014
Cash flow hedges	5	9
Not designated as hedges	(14)	75
Total volumes	(9)	84
Short position – cash flow hedges	(6)	(4)
Short position – not designated as hedges	(3,089)	(2,828)
Long position – cash flow hedges	11	13
Long position – not designated as hedges	3,075	2,903
Net (short) long position	(9)	84

(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 96% of these contracts have durations of two years or less and approximately 4% expire between two and five years.

Derivative Instruments on our Consolidated Balance Sheets

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

In millions	2015	2014
Nicor Gas	$(47)	$10
Elizabethtown Gas	(20)	2

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The following table presents the fair values and Consolidated Balance Sheets classifications of our derivative instruments as of December 31.

In millions	Classification	2015 Assets	2015 Liabilities	2014 Assets	2014 Liabilities
Designated as cash flow or fair value hedges					
Natural gas contracts	Current	$3	$(5)	$6	$(11)
Natural gas contracts	Long-term	—	(2)	—	(1)
Interest rate swap agreements	Current	9	—	—	—
Total designated as cash flow or fair value hedges		$12	$(7)	$6	$(12)
Not designated as hedges					
Natural gas and weather contracts	Current	$751	$(672)	$1,061	$(1,020)
Natural gas contracts	Long-term	179	(187)	145	(119)
Total not designated as hedges		$930	$(859)	$1,206	$(1,139)
Gross amount of recognized assets and liabilities (1) (2)		942	(866)	1,212	(1,151)
Gross amounts offset on our Consolidated Balance Sheets (2)		(724)	820	(925)	1,058
Net amounts of assets and liabilities presented on our Consolidated Balance Sheets (3)		$218	$(46)	$287	$(93)

(1) The gross amounts of recognized assets and liabilities are netted on our Consolidated Balance Sheets 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 do not include cash collateral held on deposit in broker margin accounts of $96 million as of December 31, 2015 and $133 million as of December 31, 2014. Cash collateral is included in the "Gross amounts offset on our Consolidated Balance Sheets" line of this table.

(3) As of December 31, 2015 and 2014, we held letters of credit from counterparties that under master netting arrangements would offset an insignificant portion of these assets.

Derivative Instruments on our Consolidated Statements of Income

The following table presents the impacts of our derivative instruments on our Consolidated Statements of Income for the years ended December 31.

In millions	2015	2014	2013
Designated as cash flow or fair value hedges			
Natural gas contracts – net gain (loss) reclassified from OCI into cost of goods sold	$(10)	$4	$(1)
Natural gas contracts – net gain (loss) reclassified from OCI into operation and maintenance expense	(1)	1	—
Interest rate swaps – net gain (loss) reclassified from OCI into interest expense	2	—	(3)
Income tax	1	(2)	1
Total designated as cash flow or fair value hedges, net of tax	$(8)	$3	$(3)
Not designated as hedges (1)			
Natural gas contracts - net fair value adjustments recorded in operating revenues	$56	$149	$(90)
Natural gas contracts - net fair value adjustments recorded in cost of goods sold (2)	(6)	(7)	2
Income tax	(19)	(54)	34
Total not designated as hedges, net of tax	$31	$88	$(54)
Total gains (losses) on derivative instruments, net of tax	$23	$91	$(57)

(1) Associated with the fair value of derivative instruments held at December 31, 2015, 2014 and 2013.

(2) Excludes (gains) and losses recorded in cost of goods sold associated with weather derivatives of $(12) million, $7 million and $5 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Any amounts recognized in operating income related to ineffectiveness or due to a forecasted transaction that is no longer expected to occur were immaterial for the years ended December 31, 2015, 2014 and 2013. Our expected gains and losses to be reclassified from OCI into cost of goods sold, operation and maintenance expense, interest expense and operating revenues and recognized on our Consolidated Statements of Income over the next 12 months are $2 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, 2015. The effective portions of gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in OCI during the periods are presented on our Consolidated Statements of Income. See Note 10 for these amounts.

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Note 7 - 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 plan and welfare plan. 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 trade-offs 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 5 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 the following classes of eligible employees: i) AGL Resources' non-union employees who were employed before January 1, 2012, ii) AGL Resources' union employees who were employed before January 1, 2013, iii) former Nicor employees who were employed before January 1, 1998, iv) former NUI employees who were employed on or before December 31, 2005, and v) Florida City Gas union employees as of February 1, 2008, who previously participated in a union-sponsored multiemployer plan. A defined benefit plan specifies the amount of benefits an eligible participant will eventually receive using information about the participant, including information related to the participant's earnings history, years of service and age. Our employees who are not eligible for the AGL Plan are entitled to employer provided benefits under their defined

contribution plan that exceeds the defined contribution benefits for those employees who participate in the defined benefit plan.
The benefit formula for the former 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.
Prior to 2013, we also sponsored two other tax-qualified defined benefit retirement plans for our eligible employees, the Nicor plan and NUI plan, which were merged into the AGL Plan on December 31, 2012. The participants of these former plans are now being offered their benefits, as described below, through the AGL Plan.

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Participants in the former Nicor plan, employees hired before January 1, 1998, receive noncontributory defined pension benefits. 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. The former NUI plan included substantially all of NUI Corporation's employees and provided pension benefits based on years of credited service and final average compensation as of the plan freeze date on December 31, 2005.

Welfare Benefits

We sponsor the AGL Welfare Plan, which is a defined benefit retiree health care plan for our eligible employees who reach the plan's retirement age while working for us or are receiving benefits under the AGL Resources sponsored long-term disability plan for the legacy AGL employees. This plan includes medical coverage and life insurance benefits for eligible employees: i) AGL Resources' employees who were employed as of June 30, 2002, and ii) former Nicor employees who were employed before March 18, 2014. Eligibility for these benefits is based on age and years of service.

Prior to 2013, we also sponsored the Nicor Welfare Benefit Plan, which was terminated as of January 1, 2013. 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 state regulatory agencies have approved phase-in plans that defer a portion of the related benefits expense for future recovery. Additionally, the plan terms include limits on the employer share of costs based on the coverage tier, hire date, plan elected and salary level of the employee at retirement.

The former AGL Welfare Plan requires contributions by the retirees. Our medical costs are limited to a pre-determined cap amount and eligible retirees pay 100% of the dental and vision premiums. Medicare eligible retirees covered by the former 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 former 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 former Nicor Welfare Plan requires contributions for certain categories of retirees. For employees hired on or after January 1, 1983, our medical costs are limited to a pre-determined cap amount based on their years of service at retirement.

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. The APBO associated with this plan was $2 million at December 31, 2015 and $3 million at December 31, 2014.

Assumptions

We considered a variety of factors in determining and selecting our assumptions for the discount rates at December 31. In the fourth quarter of 2015, we changed the method we use to estimate the service and interest cost components of net periodic benefit cost for our defined benefit pension and other postretirement benefit plans. Historically, we estimated the service and interest cost components using a single weighted-average discount rate derived from the yield curve used to measure the benefit obligation at the beginning of the period. We have elected to use a full yield curve approach in the estimation of these components of benefit cost by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows.

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The following table presents the components of our pension and welfare costs for the years ended December 31.

	Pension plans			Welfare plans		
Dollars in millions	2015	2014	2013	2015	2014	2013
Service cost	$28	$24	$29	$2	$2	$3
Interest cost	45	47	43	13	15	14
Expected return on plan assets	(65)	(65)	(62)	(7)	(7)	(6)
Net amortization of prior service cost	(2)	(2)	(2)	(3)	(3)	(5)
Recognized actuarial loss	31	22	35	6	6	8
Net periodic benefit cost	$37	$26	$43	$11	$13	$14
Assumptions used to determine benefit costs						
Discount rate [(1)]	4.2 %	5.0 %	4.2 %	4.0 %	4.7 %	4.0 %
Expected return on plan assets [(1)]	7.8 %	7.8 %	7.8 %	7.8 %	7.8 %	7.8 %
Rate of compensation increase [(1)]	3.7 %	3.7 %	3.7 %	3.7 %	3.7 %	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 on a before tax basis for the Welfare plans.

(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 2016 and 2017 of 2.0% and 2.0%, 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	2015	2014	2015	2014
Change in plan assets				
Fair value of plan assets, January 1,	$906	$907	$99	$93
Actual return on plan assets	(12)	68	1	5
Employee contributions	—	—	1	2
Employer contributions	2	1	17	17
Benefits paid	(49)	(70)	(20)	(19)
Medicare Part D reimbursements	—	—	1	1
Fair value of plan assets, December 31,	$847	$906	$99	$99
Change in benefit obligation				
Benefit obligation, January 1,	$1,098	$960	$334	$326
Service cost	28	24	2	2
Interest cost	45	47	13	15
Actuarial loss (gain)	(55)	137	(13)	8
Medicare Part D reimbursements	—	—	1	1
Benefits paid	(49)	(70)	(20)	(19)
Employee contributions	—	—	1	1
Benefit obligation, December 31,	$1,067	$1,098	$318	$334
Funded status at end of year	$(220)	$(192)	$(219)	$(235)
Amounts recognized on the Consolidated Balance Sheets				
Long-term asset [(2)]	$78	$97	$—	$—
Current liability	(4)	(2)	—	—
Long-term liability	(294)	(287)	(219)	(235)
Net liability at December 31,	$(220)	$(192)	$(219)	$(235)
Accumulated benefit obligation [(1)]	$1,002	$1,027	n/a	n/a
Assumptions used to determine benefit obligations				
Discount rate	4.6 %	4.2 %	4.4 %	4.0 %
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.

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Assumptions used to determine the health care benefit cost for the AGL Welfare Plan are set forth in the following table.

	2015	2014
Health care cost trend rate assumed for next year	7.9 %	8.1 %
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	$13
1% Health care cost trend rate decrease	(11)

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 effects presented above are related to the former Nicor Welfare Plan.

The following table presents the amounts not yet reflected in net periodic benefit cost and included in net regulatory assets and accumulated OCI as of December 31, 2015 and 2014.

	Net regulatory assets		Accumulated OCI		Total	
In millions	Pension plans	Welfare plans	Pension plans	Welfare plans	Pension plans	Welfare plans
December 31, 2015						
Prior service credit	$—	$(15)	$(4)	$—	$(4)	$(15)
Net loss	88	45	286	36	374	81
Total	$88	$30	$282	$36	$370	$66
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

The 2016 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	7	2	17	3	24	5

We recorded regulatory assets for anticipated future cost recoveries of $125 million and $122 million as of December 31, 2015 and 2014, respectively.

The following table presents the gross benefit payments expected for the years ended December 31, 2016 through 2025 for our pension and welfare plans. There will be benefit payments under these plans beyond 2025.

In millions	Pension plans	Welfare plans
2016	$79	$20
2017	68	20
2018	70	21
2019	73	22
2020	75	23
2021-2025	374	116

Contributions

Our employees generally do not contribute to our pension and welfare plans; however, most Nicor Gas and pre-65 AGL retirees make 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.

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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 2015 and 2014, 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 2015, $17 million in 2014 and $14 million in 2013.

Note 8 – 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, 2015, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 359,586 shares. Under the Long-Term Incentive Plan (1999), as of December 31, 2015, the number of shares issuable upon exercise of outstanding stock options, warrants and rights is 80,600 shares. The maximum number of shares available for future issuance under the Omnibus Performance Incentive Plan is 3,513,992 shares, which includes 1,514,116 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 stock awards with a grant 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 on the grant date. The following table provides additional information related to our cash and stock-based compensation awards.

In millions	2015	2014	2013
Compensation costs [1]	$40	$24	$22
Income tax benefits [1]	1	1	1
Excess tax benefits [2]	—	—	—

(1) Recorded in our Consolidated Statements of Income.

(2) Recorded in our Consolidated Balance Sheets.

Incentive and Nonqualified Stock Options

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

As of December 31, 2015 and 2014, we had no unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2015 and 2014 were $5 million and $9 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.

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Stock Options		Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding	December 31, 2012	1,528,590	$36.09		
Exercised		(617,358)	35.37		
Forfeited		(12,500)	38.36		
Outstanding (1)	December 31, 2013	898,732	$36.55		
Exercised		(267,182)	36.84		
Forfeited		(4,000)	39.71		
Outstanding (1)	December 31, 2014	627,550	$36.41	2.2	$11
Exercised		(523,400)	36.00	1.1	
Outstanding (1) (2)	December 31, 2015	104,150	$38.46	1.3	$3

(1) All options outstanding at December 31, 2015, 2014 and 2013 were exercisable.
(2) The range of exercise prices for the options outstanding at December 31, 2015 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 2015, 2014 and 2013. 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 2015 and 2014, we granted 47,546 and 44,272, respectively, of restricted stock units (including dividends) to certain employees, of which 65,042 were outstanding as of December 31, 2015. The 2015 grants had a performance measurement period that ended December 31, 2015. The performance measure, which related to earnings before interest, income tax, depreciation and amortization, was met. As such, the related restricted stock awards will be granted in 2016 and are subject to a four-year vesting schedule.

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 2015, 2014 and 2013, we granted performance share unit awards to certain officers. The 2015 performance share units have two performance measures. One measure, which accounts for 75%, relates to the company’s total shareholder return relative to a group of peer companies. The second measure, which accounts for 25%, relates to the company's earnings per share, excluding wholesale services, over the three-year performance period. The 2014 and 2013 performance share units were measured entirely based on the company’s total shareholder return relative to a group of peer companies. The recorded liability and maximum potential liability related to the 2015, 2014 and 2013 grants are as follows:

In millions	Measurement period end date	Fair value accrued at December 31, 2015	Maximum aggregate payout
Granted in 2013	December 31, 2015	$18	$24
Granted in 2014	December 31, 2016	13	28

Granted in 2015	December 31, 2017	7	29

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 2015, we issued 26,527 shares with a weighted average fair value of $50.71 to our non-employee directors.

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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 (per share)
Outstanding (1)	December 31, 2012	503,091		$39.44
Issued		175,935		42.41
Forfeited		(33,352)		40.64
Vested		(204,421)		38.71
Outstanding (1)	December 31, 2013	441,253		$40.82
Issued		262,235		47.03
Forfeited		(14,895)		43.41
Vested		(225,683)		42.31
Outstanding (1)	December 31, 2014	462,910	1.8	$43.54
Issued		274,012	3.1	51.38
Forfeited		(13,390)	2.5	45.60
Vested		(324,700)	—	51.68
Outstanding (1)	December 31, 2015	398,832	1.4	$46.92

(1) Subject to restriction.

Employee Stock Purchase Plan (ESPP)

We have a nonqualified, broad-based ESPP for all eligible employees. As of December 31, 2015, there were 315,570 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. The following table provides additional information about our ESPP as of December 31.

	2015	2014	2013
Shares purchased on the open market	106,994	100,199	97,734
Average purchase price (per share)	$55.47	$51.60	$42.96
Total purchase price discount (in dollars)	$793,931	$739,598	$628,358

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Note 9 - 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 or ranges, year-to-date weighted average interest rates and amounts outstanding for our various debt securities and facilities that are included on our Consolidated Balance Sheets.

Dollars in millions	Year(s) due	December 31, 2015 Weighted average interest rate (1)		December 31, 2015 Outstanding		December 31, 2014 Weighted average interest rate (1)		December 31, 2014 Outstanding	
Short-term debt									
Commercial paper - AGL Capital (2)	2016	0.5	%	$471		0.3	%	$590	
Commercial paper - Nicor Gas (2)	2016	0.4		539		0.2		585	
Total short-term debt		0.4	%	$1,010		0.3	%	$1,175	
Current portion of long-term debt	2016	4.9	%	$545		5.0	%	$200	
Long-term debt - excluding current portion									
Senior notes	2018-2043	5.0	%	$2,455		5.0	%	$2,625	
First mortgage bonds	2019-2038	5.9		375		5.6		500	
Gas facility revenue bonds	2022-2033	0.9		200		0.9		200	
Medium-term notes	2017-2027	7.8		181		7.8		181	
Total principal long-term debt		4.9	%	$3,211		4.9	%	$3,506	
Unamortized fair value adjustment of long-term debt (3)	2016-2038	n/a		68		n/a		80	
Unamortized debt premium, net	n/a	n/a		16		n/a		16	
Unamortized debt issuance costs	n/a	n/a		(20	)	n/a		(21	)
Total non-principal long-term debt		n/a		64		n/a		75	
Total long-term debt - excluding current portion				$3,275				$3,581	
Total debt				$4,830				$4,956	

(1) Interest rates are calculated based on the daily weighted average balance outstanding for the years ended December 31, 2015 and 2014.

(2) As of December 31, 2015, the effective interest rates on our commercial paper borrowings were 0.7% for AGL Capital and 0.5% for Nicor Gas.

(3) See Note 5 herein for additional information on our fair value measurements.

Short-term Debt

Our short-term debt at December 31, 2015 and 2014 was composed of borrowings under our commercial paper programs.

Commercial Paper Programs We maintain commercial paper programs at AGL Capital and at Nicor Gas that consist of short-term, unsecured promissory notes 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. Nicor Gas' commercial paper program supports working capital needs at Nicor Gas, while all of our other subsidiaries and SouthStar participate in AGL Capital's commercial paper program. During 2015, our commercial paper maturities ranged from 1 to 63 days and at December 31, 2015, remaining terms to maturity ranged from 4 to 43 days. During 2015, total borrowings and repayments netted to a payment of $165 million. During 2015 there were no commercial paper issuances with original maturities over three months.

Credit Facilities On October 30, 2015, we entered into agreements to amend and extend the AGL Credit Facility and Nicor Gas Credit Facility. Under the terms of these agreements, we extended the maturity dates of the AGL Credit

Facility and the Nicor Gas Credit Facility to November 9, 2018 and December 14, 2018, respectively. One of the banks elected not to participate in this extension and its total commitment of $75 million will continue through the fourth quarter of 2017. We also modified the credit facilities to provide for the limited consent by the lenders to the proposed merger with Southern Company. Additionally, we made similar changes to our Bank Rate Mode Covenants Agreement. At December 31, 2015 and 2014, there were no outstanding borrowings under either the AGL Capital or Nicor Gas credit facility.

Current Portion of Long-term Debt The current portion of our long-term debt at December 31, 2015 is composed of the portion of our long-term debt due within the next 12 months.

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Long-term Debt

Our long-term debt at December 31, 2015 and 2014 consisted of medium-term notes: Series A, Series B, and Series C; senior notes; first mortgage bonds; and gas facility revenue bonds. 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 2020. The annual maturities of our long-term debt for the next five years and thereafter are as follows:

Year	Amount (in millions)
2016	$545
2017	22
2018	155
2019	350
2020	—
Thereafter	2,684
Total	$3,756

Senior Notes On November 18, 2015 AGL Capital issued $250 million in 10-year senior notes at a fixed interest rate of 3.875%. The net proceeds from the senior notes, which are guaranteed by AGL Capital, were used to repay a portion of AGL Capital's commercial paper, including $200 million we borrowed to repay our senior notes that matured on January 15, 2015. The balance of the net proceeds will be used for general corporate purposes, including capital expenditures associated with increased utility investment and construction of our new pipeline projects.

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 our senior note issuance in the fourth quarter of 2015 and our anticipated issuances in 2016. We have designated the forward-starting interest rate swaps, which are settled on the respective debt issuance dates, as cash flow hedges. We settled $200 million of these interest rate swaps on November 18, 2015, in conjunction with the aforementioned senior note issuance, at which time we received $248 million in net proceeds that are classified as a financing activity on the Consolidated Statements of Cash Flow. The $2 million of debt issuance costs will be amortized to reduce interest expense over the remaining term of the senior notes. We performed a qualitative assessment of effectiveness as of December 31, 2015 and concluded that the remaining hedges are highly effective.

First Mortgage Bonds We assumed the first mortgage bonds of Nicor Gas as a result of the 2011 merger with Nicor.

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 five series of gas facility revenue bonds have been issued. These revenue bonds are issued by state agencies or counties to investors, and proceeds from the issuance then are loaned to us.

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 month. The following table contains our debt-to-capitalization ratios as of December 31, which are below the maximum allowed.

	AGL Resources		Nicor Gas	
	2015	2014	2015	2014
Debt covenants (1)	54 %	55 %	56 %	62 %

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

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; and
- 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, 2015 and 2014.

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Note 10 - Equity
Preferred Securities
At December 31, 2015 and 2014, 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.
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 6. For more information on our pensions and retirement benefit obligations, see Note 7. Our OCI (loss) amounts are aggregated within accumulated other comprehensive loss on our Consolidated Balance Sheets. 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 at December 31, 2012	$(3)	$(215)	$(218)
OCI, before reclassifications	1	66	67
Amounts reclassified from accumulated OCI	3	12	15
Balance at December 31, 2013	1	(137)	(136)
OCI, before reclassifications	(6)	(71)	(77)
Amounts reclassified from accumulated OCI	(1)	8	7
Balance at December 31, 2014	(6)	(200)	(206)
OCI, before reclassifications	—	—	—
Amounts reclassified from accumulated OCI	8	12	20
Balance at December 31, 2015	$2	$(188)	$(186)

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

The following table provides details of the reclassifications out of accumulated other comprehensive loss and the favorable (unfavorable) impact on net income for the years ended December 31.

In millions (1)	December 31, 2015	2014
Cash flow hedges		
Cost of goods sold (natural gas contracts)	$(10)	$4
Operation and maintenance expense (natural gas contracts)	(1)	1
Interest expense (interest rate contracts)	2	—
Total before income tax	(9)	5
Income tax	1	(2)
Cash flow hedges, net of income tax	(8)	3
Less noncontrolling interest	—	2

Total cash flow hedges, net of income tax	(8)	1
Retirement benefit plans		
Operation and maintenance expense (actuarial losses) [2]	(22)	(15)
Operation and maintenance expense (prior service credits) [2]	2	2
Total before income tax	(20)	(13)
Income tax	8	5
Total retirement benefit plans, net of income tax	(12)	(8)
Total reclassification	$(20)	$(7)

(1) Amounts in parentheses indicate debits, or reductions, to our net income and credits 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 7 for additional details about net periodic benefit cost.

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Note 11 - 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 3.

On December 9, 2015, we notified Piedmont of our election, in accordance with the change in control provisions in the Second Amended and Restated Limited Liability Company Agreement of SouthStar, to purchase its entire 15% interest in SouthStar at fair market value. The parties currently are negotiating final terms.

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; and
- 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; and
- 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 of $3 million, $7 million and $3 million for the years ended December 31, 2015, 2014 and 2013, respectively. 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, which generally occurs in the first quarter of each fiscal year. For the years ended December 31, 2015, 2014 and 2013, SouthStar distributed $18 million, $17 million and $17 million, respectively, to Piedmont.

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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 Balance Sheets 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 Balance Sheets. The SouthStar amounts exclude intercompany eliminations and the balances of our wholly owned subsidiary with an 85% ownership interest in SouthStar.

	2015				2014			
In millions	Consolidated	SouthStar	%		Consolidated	SouthStar	%	
Current assets	$2,115	$245	12	%	$2,886	$236	8	%
Goodwill and other intangible assets	1,922	114	6		1,952	125	6	
Long-term assets and other deferred debits	10,717	16	—		10,050	17	—	
Total assets	$14,754	$375	3	%	$14,888	$378	3	%
Current liabilities	$3,000	$54	2	%	$3,219	$71	2	%
Long-term liabilities and other deferred credits	7,779	—	—		7,841	—	—	
Total liabilities	10,779	54	1		11,060	71	1	
Equity	3,975	321	8		3,828	307	8	
Total liabilities and equity	$14,754	$375	3	%	$14,888	$378	3	%

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	2015	2014
Operating revenues	$711	$866
Operating expenses		
Cost of goods sold	490	645
Operation and maintenance	81	87
Depreciation and amortization	10	11
Taxes other than income taxes	1	1
Total operating expenses	582	744
Operating income	$129	$122

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, 2015, 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 a 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.

Pipeline Development Investments In the third quarter of 2014, we entered into partnerships to form two new interstate pipeline companies within our midstream operations segment, as described below. The capacity from these pipelines 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 companies are VIEs. We are not considered the primary beneficiary and, therefore, we have not consolidated the financial statements for these companies on 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 investments in these companies using the equity method of accounting, and have classified the investments within other noncurrent assets on our Consolidated Balance Sheets. The contractual commitments and obligations, including agreements with third-party providers, of these VIEs for which we are not the primary beneficiary 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 is considered to be immaterial.
PennEast Pipeline In August 2014, we entered into a partnership in which we hold a 20% ownership interest in an interstate pipeline company formed to develop and operate a 118-mile natural gas pipeline between New Jersey and Pennsylvania. The initial transportation capacity of 1.0 Bcf per day, which may be expanded to 1.2 Bcf per day, is under long-term contracts, mainly by public utilities and other market-serving entities, such as electric generation companies, in New Jersey, Pennsylvania and New York.
Atlantic Coast Pipeline In September 2014, we entered into a project in which we hold a 5% ownership interest to develop and operate a 564-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.

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Sawgrass Storage We previously owned 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 that 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. This joint venture was dissolved in May 2015.

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

In millions	2015	2014
Triton	$49	$62
Horizon Pipeline	14	14
PennEast Pipeline	9	1
Atlantic Coast Pipeline	7	2
Other	1	1
Total	$80	$80

Income from our equity method investments is classified as other income on our Consolidated Statements of Income. The following table provides the income from our equity method investments for the years ended December 31. For more information on our other income, see Note 3.

In millions	2015	2014	2013
Triton	$4	$6	$9
Horizon Pipeline	2	2	2
Other	—	—	(8)

Note 12 - Commitments, Guarantees and Contingencies

We incur 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 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 commercial arrangements that are directly supported by related revenue-producing activities. In April 2015, Nicor Gas entered into a series of natural gas purchase obligations in the ordinary course of business, 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, 2015.

In millions	Total	2016	2017	2018	2019	2020	2021 & thereafter
Recorded contractual obligations:							
Long-term debt	$3,756	$545	$22	$155	$350	$—	$2,684
Short-term debt	1,010	1,010	—	—	—	—	—
Environmental remediation liabilities (1)	431	67	79	70	61	52	102
Total	$5,197	$1,622	$101	$225	$411	$52	$2,786
Unrecorded contractual obligations and commitments (2) (7):							
Pipeline charges, storage capacity and gas supply (3)	$5,007	$795	$536	$392	$370	$318	$2,596
Interest charges (4)	2,418	181	158	156	151	133	1,639
Operating leases (5)	159	31	26	18	16	15	53
Asset management agreements (6)	28	11	9	6	2	—	—
Standby letters of credit, performance/surety bonds (7)	73	73	—	—	—	—	—
Other	5	3	1	1	—	—	—
Total	$7,690	$1,094	$730	$573	$539	$466	$4,288

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

(2) In accordance with GAAP, these items are not reflected on our Consolidated Balance Sheets.

(3) 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 37 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2015, and is valued at $76 million. As we do for certain of our affiliates, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(4) Floating rate interest charges are calculated based on the interest rate as of December 31, 2015 and the maturity date of the underlying debt instrument. As of December 31, 2015, we have $49 million of accrued interest on our Consolidated Balance Sheets that will be paid in 2016.

(5) 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.

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

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

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We are also involved in legal or administrative proceedings before various courts and agencies with respect to general claims, environmental remediation and other matters. Although we are unable to determine the ultimate outcomes of these contingencies, we believe that our financial statements appropriately reflect these amounts, including the recording of liabilities when a loss is probable and reasonably estimable.

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 liabilities have been recorded for such guarantees and indemnifications, as the fair values were 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, 2015. 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 the "Environmental Matters" section below. 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.

Regulatory Matters

In February 2015, Atlanta Gas Light made a filing with the Georgia Commission for a rate true-up of allowed unrecovered revenue of $178 million through December 2014 related to its PRP. In October 2015, Atlanta Gas Light received a final order from the Georgia Commission, which represented a resolution of all matters previously outstanding before the Georgia Commission, including a final determination of the true-up recovery related to the PRP. This order allows Atlanta Gas Light to recover $144 million of the $178 million unrecovered program revenue that was requested in its February 2015 filing. The remaining unrecovered amount relates primarily to recoveries of previously allowed rate of return amounts, which are included in our unrecognized ratemaking amount and does not have a material impact on our consolidated financial statements as of December 31, 2015. Provisions in the order resulted in the recognition of $1 million of interest expense related to the PRP true-up for the year ended December 31, 2015 on our Consolidated Statements of Income.

We began recovering the $144 million in October 2015 through the monthly PRP surcharge, which increased by $0.82 on October 1, 2015 and will further increase by $0.81 on each of October 1, 2016 and October 1, 2017. The cumulative total monthly increase to the PRP surcharge will remain at $2.44 and be effective until the earlier of the full recovery of the under-recovered amount or December 31, 2025. During 2015 we recognized $2 million of revenue for this program.

Additionally, one of the capital projects under the PRP experienced construction issues on certain segments in late 2013, and prior to these segments being placed into service it was necessary to complete mitigation work. The order from the Georgia Commission allows for the recovery of these mitigation costs in future base rates, but delayed such recovery until at least March 31, 2017. Provisions in the order resulted in the recognition of $5 million in operation and maintenance expense for the year ended December 31, 2015 on our Consolidated Statements of Income. Atlanta Gas Light continues to pursue contractual and legal claims against certain third-party contractors in connection with the mitigation costs incurred for construction issues experienced in finalizing the PRP. Any amounts recovered through the legal process will be retained by Atlanta Gas Light. At March 31, 2017, the total capitalized mitigation cost for which Atlanta Gas Light will seek recovery in future rates is approximately $28 million.

In August 2014, staff of the Illinois Commission and the CUB filed testimony in the Nicor Gas 2003 gas cost prudence review disputing certain gas loan transactions offered by Nicor Gas under its Chicago Hub services and 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 transactions reduced ratepayers' costs as either credits to the PGA or reductions to base rates consistent with then-current Illinois Commission orders governing these activities. In July 2015, the Administrative Law Judge issued a proposed order concluding that Nicor Gas' supply costs and purchases in 2003 were prudent, its reconciliation of the related costs was proper, and the propositions by the staff of the Illinois Commission and the CUB were based on hindsight speculation, which is expressly prohibited in a prudence review examination. In September 2015, the Illinois Commission issued a final order approving the proposal of the Administrative Law Judge. In November 2015, the Illinois Commission granted the CUB's petition for a rehearing on this matter. In February 2016, the Administrative Law Judge issued a proposed order on rehearing affirming the original order by the Illinois Commission, which now requires approval by the Illinois Commission.

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In December 2012, we 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, which was approved by the Georgia Commission in December 2014. During the first half of 2015, discretionary funds available to the Universal Service Fund, which is controlled by the Georgia Commission, were used to resolve their obligation of 25% of the imbalance, or approximately 1.15 Bcf of natural gas. Atlanta Gas Light was also obligated to resolve 25% of the 4.6 Bcf imbalance, or approximately 1.15 Bcf of natural gas, through system injections, which were fully replaced by September 30, 2015.

Environmental Matters

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control that require us to remove or remedy the effect on the environment of the disposal or release of specified substances at our current and former operating sites. See Note 4 for additional information on our environmental remediation costs.

In September 2015, the EPA filed an administrative complaint and notice of opportunity for hearing against Nicor Gas. The complaint alleges violation of the regulatory requirements applicable to polychlorinated biphenyls in the Nicor Gas distribution system and the EPA seeks a total civil penalty of approximately $0.3 million. While we are unable to predict the ultimate outcome of this matter, 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 resolutions of these contingencies, whether individually or in aggregate, could be material to earnings in a particular period, they will not have a material adverse effect on our consolidated financial position or cash flows for the year.

The company and each member of the Board were named as defendants in four purported shareholder class action lawsuits filed in the United States District Court for the Northern District of Georgia, Atlanta Division, which we refer to as the "Court": Patrick Baker v. AGL Resources Inc., et al., which we refer to as the "Baker Action", Jeff Morton v. AGL Resources Inc., et al., which we refer to as the "Morton Action", Sarah Halberstam and Baruch Z. Halberstam (as custodian for Benjamin Halberstam) v. AGL Resources Inc., et al., which we refer to as the "Halberstam Action", and Manuel Abt v. AGL Resources, Inc., et al., which we refer to as the "Abt Action", filed on September 16, 2015, September 22, 2015, September 28, 2015 and October 9, 2015, respectively. Southern Company and Merger Sub were also named as defendants in the Baker Action and the Morton Action. We refer to the Baker Action, the Morton Action, the Halberstam Action and the Abt Action, collectively, as the "Actions". The Actions alleged that our preliminary proxy statement contained false and misleading statements and omitted material information in violation of certain provisions under the Exchange Act. The Actions also alleged that the members of the Board were liable for those alleged misstatements and omissions. The Morton Action further alleged that the members of the Board breached their fiduciary duties owed to the shareholders of the company in connection with the merger and that Southern Company and Merger Sub aided and abetted such breaches. The Actions sought, among other things, preliminary and permanent injunctive relief enjoining the merger, rescission or rescissory damages in the event the merger is implemented and an award of attorneys' and experts' fees and costs. On October 23, 2015, the Court consolidated the four actions, and on January 5, 2016, the Court dismissed the consolidated action without prejudice.

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.
In June 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. All refunds were completed in the first half of 2014. The CUB's February 28, 2014 appeal of the Illinois Commission’s order requesting refunds consistent with its 2009 request was rejected by the appellate court in Illinois on March 18, 2015.

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Note 13 - 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 on the Consolidated Statements of Income are shown in the following table.

In millions	2015	2014	2013
Current income taxes			
Federal [1]	$(11)	$113	$164
State	10	38	35
Deferred income taxes			
Federal	198	184	(8)
State	18	17	(11)
Amortization of investment tax credits	(2)	(2)	(3)
Total income tax expense	$213	$350	$177

(1) We incurred an $11 million federal net operating loss in 2015, which will be carried back and fully utilized against prior year income tax.

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, on our Consolidated Statements of Income are presented in the following table.

In millions	2015	2014	2013
Computed tax expense at statutory rate	$205	$325	$165
State income tax, net of federal income tax benefit	21	36	20
Tax effect of net income attributable to the noncontrolling interest	(8)	(7)	(7)
Amortization of investment tax credits	(2)	(2)	(3)
Affordable housing credits	(1)	(2)	(2)
Flexible dividend deduction	(2)	(2)	(2)
Sale of Compass Energy	—	—	6
Other	—	2	—
Total income tax expense	$213	$350	$177

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 on our Consolidated Balance Sheets. 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 on our Consolidated Balance Sheets. 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.

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In millions	As of December 31, 2015	2014
Current accumulated deferred income tax liabilities		
Mark-to-market	$37	$33
Inventory	53	26
Total current accumulated deferred income tax liabilities	90	59
Current accumulated deferred income tax assets		
Compensation accruals	30	30
Lower of cost or market	6	26
Allowance for doubtful accounts	8	12
Other	19	21
Total current accumulated deferred income tax assets	63	89
Valuation allowances [(1)]	(4)	(6)
Total current accumulated deferred income tax assets, net of valuation allowances	59	83
Net current accumulated deferred income tax (liability) asset	$(31)	$24
Long-term accumulated deferred income tax liabilities		
Property - accelerated depreciation and other property-related items	$2,019	$1,801
Investments in partnerships	12	16
Acquisition intangibles	12	14
Mark-to-market	1	12
Other	102	85
Total long-term accumulated deferred income tax liabilities	2,146	1,928
Long-term accumulated deferred income tax assets		
Unfunded pension and retiree welfare benefit obligation	120	117
Deferred investment tax credits	5	6
Other	124	95
Total long-term accumulated deferred income tax assets	249	218
Valuation allowances [(1)]	(15)	(14)
Total long-term accumulated deferred income tax assets, net of valuation allowances	234	204
Net long-term accumulated deferred income tax liability	$1,912	$1,724

(1) The total valuation allowance in 2015 and 2014 is $19 million and $20 million, respectively. For 2015, the valuation allowance is related to our investment in Triton. For 2014, the total is composed of $1 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 a reduction of the valuation allowance.

Tax Benefits

As of December 31, 2015 and December 31, 2014, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2016. As of December 31, 2015, we did not have a liability recorded for payment of interest or penalties associated with uncertainty in income taxes, nor did we have any such interest or penalties during 2015 or 2014.

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 2012.

Note 14 - Segment Information

Our reportable segments comprise revenue-generating components of the 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 and midstream operations. Our non-reportable segments are combined and presented as “other.”

In September 2014, we sold Tropical Shipping, which historically operated within our cargo shipping segment. The financial results of these businesses for the years ended December 31, 2014 and 2013 are reflected as discontinued operations on the Consolidated Statements of Income. Amounts shown in this note for total assets as of December 31, 2013 exclude assets held for sale and other amounts shown, unless otherwise indicated, exclude 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 15 for additional information.

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Our distribution operations segment is the largest component of our business and includes natural gas local distribution utilities that construct, manage and maintain intrastate natural gas pipelines and distribution facilities in seven states. Although the operations of this segment are geographically dispersed, the operating subsidiaries within the segment are regulated utilities with rates determined by individual state regulatory agencies. 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 equipment protection products and services. Our wholesale services segment engages in natural gas storage and gas pipeline arbitrage and related activities. Additionally, this segment provides 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 segment includes subsidiaries that are not significant on a stand-alone basis and that do not align with one of our reportable segments.

The chief operating decision maker of the company is the 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 and excludes income taxes and interest expense, which we evaluate on a consolidated basis. Summarized statements of income, balance sheets and capital expenditure information by segment as of and for the years ended December 31 are shown in the following tables.

2015

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other	Intercompany eliminations	Consolidated
Operating revenues from external parties	$2,880	$835	$202	$55	$11	$(42)	$3,941
Intercompany revenues	169	—	—	—	—	(169)	—
Total operating revenues	3,049	835	202	55	11	(211)	3,941
Operating expenses							
Cost of goods sold	1,291	518	19	19	4	(206)	1,645
Operation and maintenance	687	137	67	25	3	(5)	914
Depreciation and amortization	336	25	1	18	17	—	397
Taxes other than income taxes	164	3	3	5	6	—	181
Merger-related expenses	—	—	—	—	44	—	44
Goodwill impairment	—	—	—	14	—	—	14
Total operating expenses	2,478	683	90	81	74	(211)	3,195
Operating income (loss)	571	152	112	(26)	(63)	—	746
Other income (expense)	9	—	(4)	3	5	—	13
EBIT	$580	$152	$108	$(23)	$(58)	$—	$759
Total assets	$12,517	$686	$935	$692	$9,664	$(9,740)	$14,754
Capital expenditures	$957	$7	$2	$27	$—	$34	$1,027

2014

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other	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
Total assets	$12,037	$670	$1,402	$694	$9,706	$(9,621)	$14,888
Capital expenditures	$715	$11	$2	$15	$26	$—	$769

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2013

In millions	Distribution operations	Retail operations	Wholesale services (1)	Midstream operations	Other	Intercompany eliminations	Consolidated
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
Total assets (2)	$11,629	$685	$ 1,163	$713	$10,426	$(10,088)	$ 14,528
Capital expenditures	$684	$9	$ 2	$12	$24	$—	$ 731

(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
2015	$6,286	408	6,694	6,492	$202
2014	$10,709	718	11,427	10,849	$578
2013	$7,681	417	8,098	8,038	$60

(2) Total assets reported as of December 31, 2013 exclude assets held for sale.

Note 15 - Discontinued Operations

In September 2014, we sold 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 recorded a non-cash goodwill impairment charge of $19 million, for which there was no income tax benefit. Additionally, we recognized a total charge of $7 million in the second and third quarters of 2014 related to the suspension of depreciation and amortization on assets for which we were not compensated by the buyer.

The financial results of these businesses are reflected as discontinued operations, and the 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
Operating revenues	$243	$365
Operating expenses		
Cost of goods sold	149	222
Operation and maintenance (1)	75	110
Depreciation and amortization (2)	5	19

Taxes other than income taxes	5	6
Loss on sale and goodwill impairment [3]	28	—
Total operating expenses	262	357
Operating (loss) income	(19)	8
(Loss) income before income taxes	(19)	8
Income tax expense [4]	(61)	(3)
(Loss) income from discontinued operations, net of tax	$(80)	$5

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

(2) We ceased depreciating and amortizing Tropical Shipping's assets on April 4, 2014.

(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 16 - Selected Quarterly Financial Data (Unaudited)

The variance in our quarterly earnings is primarily the result of the seasonal nature of the distribution of natural gas to customers, the volatility within our wholesale services segment and the 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 2015 operating revenues and operating income were lower than 2014, primarily as a result of significantly colder-than-normal weather in 2014, lower volatility in the natural gas market and transportation constraints in the Northeast and Midwest. Our quarterly financial data for 2015 and 2014 are summarized below.

In millions, except per share amounts	March 31	June 30	September 30	December 31
2015				
Operating revenues	$1,721	$674	$584	$962
Operating income	364	107	59	216
EBIT	367	111	61	220
Net income	205	44	12	112
Net income attributable to AGL Resources	193	42	11	107
Basic earnings (loss) per common share	1.62	0.35	0.09	0.89
Diluted earnings (loss) per common share	1.62	0.35	0.09	0.89
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	334	57	23	148
(Loss) income from discontinued operations, net of tax	(50)	1	(31)	—
Net income (loss) attributable to AGL Resources	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)	—

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 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.

Glossary

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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, 2015. No system of controls, no matter how well-designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases. Our disclosure controls and procedures, however, are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2015. 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.

Changes in Internal Control over Financial Reporting

There were no changes to our internal control over financial reporting during the fourth quarter ended December 31, 2015 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, 2015. 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.

ITEM 9B. OTHER INFORMATION

None

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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. All information is as of the date of the filing of this report.

Name, age and position with the company	Periods served
Andrew W. Evans, Age 49	
President and Chief Executive Officer	January 2016 - Present
President and Chief Operating Officer	May 2015 - December 2015
Executive Vice President and Chief Financial Officer	May 2006 - May 2015
Elizabeth W. Reese, Age 47	
Executive Vice President and Chief Financial Officer	May 2015 - Present
Senior Vice President and President of Nicor Gas	June 2012 - May 2015
Senior Vice President and President of Retail Services	December 2011 - June 2012
Vice President, Operational Planning and Analysis	June 2010 - December 2011
Vice President, Finance	July 2007 - June 2010
Henry P. Linginfelter, Age 55	
Executive Vice President, Distribution Operations	December 2011 - Present
Executive Vice President, Utility Operations	June 2007 - December 2011
Melanie M. Platt, Age 61	
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 58	
Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 - Present
Peter I. Tumminello, Age 53	
Executive Vice President, Nonregulated Businesses and President Sequent	May 2015 - Present
Executive Vice President, Wholesale Services, and President Sequent	December 2011 - May 2015
President Sequent	April 2010 - December 2011

Directors of the Registrant

Set forth below are the names, ages, positions and offices of our directors along with their business experience during the past five years. All information is as of the date of the filing of this report.

Sandra N. Bane, former audit partner with KPMG LLP from 1985 until her retirement in 1998; head of the Western Region's Merchandising practice at KPMG LLP and partner in charge of the region's Human Resources department for two years; accountant with increasing responsibilities at KPMG LLP from 1975 until 1996; currently a director of Big 5 Sporting Goods Corporation and Transamerica Asset Management Group, a mutual fund company; and formerly a director of PETCO Animal Supplies, Inc. Ms. Bane, 63, has been a director of AGL Resources since February 2008. Ms. Bane brings many years of experience as an audit partner at KPMG with extensive financial accounting knowledge that is critical to our Board. Ms. Bane's experience with accounting principles, financial reporting rules and regulations, evaluating financial results and generally overseeing the financial reporting process of large public companies from an independent auditor's perspective and as a board member and audit committee member of other public companies makes her an invaluable asset to our Board.

Thomas D. Bell, Jr., Chairman of Mesa Capital Partners, LLC, a real estate investment firm, since 2011; former Chairman of SecurAmerica LLC, a provider of premium contract security services, from January 2010 to September 2012; former Chairman and Chief Executive Officer of Cousins Properties Incorporated, a fully integrated real estate investment trust, from December 2006 until July 2009; President and Chief Executive Officer of Cousins Properties Incorporated from January 2002 until December 2006; real estate consultant to Credit Suisse First Boston from August 2001 until January 2002; special limited partner at Forstmann Little from January 2001 until July 2001;

Chairman and Chief Executive Officer of Young & Rubicam, Inc. from January 2000 until November 2000; President and Chief Operating Officer of Young & Rubicam, Inc. from September 1999 until January 2000; Chairman and Chief Executive Officer of Young & Rubicam Advertising from March 1998 until August 1999; currently a director of Regal Entertainment Group, Norfolk Southern Corporation and the US Chamber of Commerce; and formerly a director of Cousins Properties Incorporated, Credit Suisse First Boston, Credit Suisse Group and Lincoln Financial Group. Mr. Bell, 66, has been a director of AGL Resources since July 2004. Mr. Bell previously served as a director of AGL Resources from July 2003 until April 2004.

Mr. Bell’s extensive experience as a chief executive officer and chief operating officer of public companies demonstrates his leadership capability and business acumen. His experience with complex financial and operational issues in the real estate industry along with his service on the board of directors of a variety of public companies, including such companies’ audit and compensation committees, brings valuable financial, operational and strategic expertise to our Board.

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Norman R. Bobins, Chief Executive of Norman Bobins Consulting LLC, an independent consulting firm, since 2008; Chairman of The PrivateBank- Chicago since 2008; President and Chief Executive Officer of ABN AMRO North America from 2006 to 2007; Senior Executive Vice President of ABN AMRO Bank N.V. from 2002 to 2007; President and Chief Executive Officer of LaSalle Bank Corporation from 2003 to 2007; Chairman, President and Chief Executive Officer of LaSalle Bank from 2000 to 2007; President of LaSalle Bank Midwest from 2005 to 2007; currently a director of AAR Corp., Omega Healthcare Investors, Inc. and PrivateBancorp, Inc.; and formerly a director of SIMS Metal Management. Mr. Bobins, 73, has been a director of AGL Resources since December 2011 and was a director of Nicor from 2007 to 2011.

Mr. Bobins has held several senior executive positions at various banking institutions, including LaSalle Bank Corporation, which was one of the largest bank holding companies in the Midwest, and where Mr. Bobins served as Chairman, Chief Executive Officer and President. Mr. Bobins' extensive knowledge of and experience in banking and finance and his prominent position in the Midwestern business community qualify him to serve on our Board. We also benefit from Mr. Bobins' extensive experience in leadership roles with numerous business, civic and philanthropic organizations in the Chicago area, which helps provide us with important business insights and access to other business leaders.

Charles R. Crisp, former President and Chief Executive Officer of Coral Energy, LLC, a subsidiary of Shell Oil Company, which provided energy-related products and services associated with wholesale natural gas and power, from 1999 until his retirement in October 2000; President and Chief Operating Officer of Coral Energy, LLC from 1998 until 1999; joined Houston Industries in 1996 and served as President of its domestic power generation group until 1998; served as President, Chief Operating Officer and a director of Tejas Gas Corporation from 1988 until 1996; joined Houston Pipe Line Co. in 1985 where he served as a Vice President, Executive Vice President and President until 1988; served as Executive Vice President of Perry Gas Companies Inc. from 1982 until 1985; began his career in the energy industry in 1969 with Conoco Inc. where he held various engineering, operations and management positions from 1969 until 1982; currently a director of EOG Resources Inc., Intercontinental Exchange, Inc. and Targa Resources Corp. Mr. Crisp, 68, has been a director of AGL Resources since April 2003.

Mr. Crisp's extensive energy experience is critical to our Board. Mr. Crisp's vast understanding of many aspects of our industry and his experience serving on the board of directors of three other public companies in the energy industry are invaluable. In addition, Mr. Crisp's leadership and business experience and deep knowledge of various sectors of the energy industry provide our Board with crucial insight.

Andrew W. Evans, President and Chief Executive Officer of AGL Resources. Mr. Evans joined the company in April 2002 as Vice President and Treasurer and served in this role until September 2005. He subsequently served as Senior Vice President and Chief Financial Officer from September 2005 to May 2006 and as Executive Vice President and Chief Financial Officer from May 2006 to May 2015. Mr. Evans was appointed to serve as President and Chief Operating Officer in May 2015 and became President and Chief Executive Officer in January 2016. Mr. Evans, 49, has been a director of AGL Resources since January 1, 2016.

With over 22 years of energy industry experience at almost every level of a large public company, Mr. Evans is well positioned to lead our management team and provide essential insight and guidance to the Board from an inside perspective of our day-to-day operations, along with experience and comprehensive knowledge of the natural gas industry.

Brenda J. Gaines, former President and Chief Executive Officer of Diners Club North America, a division of Citigroup, a charge and credit card services company, from 2002 until her retirement in 2004; President of Diners Club North America from 1999 to 2004; Executive Vice President-Corporate Card Sales of Diners Club North America from 1994 to 1999; currently a director of Federal National Mortgage Association (Fannie Mae) and Tenet Healthcare Corporation; and formerly a director of CNA Financial Corporation and Office Depot, Inc. Ms. Gaines, 66, has been a director of AGL Resources since December 2011 and was a director of Nicor from 2006 to 2011.

Ms. Gaines has more than 28 years of experience working in the corporate and government arenas. She served as the mayor's deputy chief of staff and commissioner of housing for the City of Chicago. She has substantial training in corporate governance and has served as a speaker and panel member in various Risk Metrics certified courses on corporate governance, particularly those focusing on audit committees. As President and Chief Executive Officer of

Diners Club North America, Ms. Gaines led the activities for the North American franchise of the $29 billion Diners Club International network. Ms. Gaines' business leadership skills, marketing knowledge, and experience in government service and on the boards of directors of other companies qualify Ms. Gaines to serve on our Board. In addition, Ms. Gaines' corporate governance training and experience provides our Board with valuable insight and expertise.

Arthur E. Johnson, former Senior Vice President, Corporate Strategic Development, of Lockheed Martin Corporation, an advanced technology company engaged in research, design, development, manufacture and integration of advanced technology systems, from 2001 until his retirement in March 2009; Vice President, Corporate Strategic Development, of Lockheed Martin Corporation from 1999 until 2001; President and Chief Operating Officer of Lockheed Martin Corporation Information and Services Sector from 1997 until 1999; President of Lockheed Martin Corporation Systems Integration Group from April 1996 until August 1997; President of Loral Corporation Federal Systems Group from 1994 until 1996; currently a director of Booz Allen Hamilton Inc. and Eaton Corporation Plc and Vice Chairman of the independent trustees of Fidelity Investments Fixed Income and Asset Allocation Funds; and formerly a director of Delta Air Lines Inc. and IKON Office Solutions Corporation.

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Mr. Johnson, 69, has been a director of AGL Resources since February 2002 and served as Lead Director of our Board from April 2009 to April 2015.

Mr. Johnson brings many years of experience in senior management with significant responsibilities in the areas of large company management and operations, business strategy development and strategic partnerships, which provide valuable insight to our Board. He also possesses extensive experience in the area of information services and technology that is extremely valuable to our Board. In addition, Mr. Johnson's service on the board of directors of other public companies brings valuable experience and insight to our Board.

Wyck A. Knox, Jr., retired partner in, and former Chairman of the Executive Committee (for four years) of, the law firm of Kilpatrick Stockton LLP, now Kilpatrick Townsend & Stockton, LLP, from 1976 until his retirement in 2007; and Chairman and Chief Executive Officer of Knox Rivers Construction Company from 1976 until 1995. Mr. Knox, 75, has been a director of AGL Resources since November 1998.

With over 50 years of legal experience and deep-rooted affiliations with a diverse array of business, political and philanthropic organizations in Georgia, Mr. Knox brings immense insight to our Board from the perspective of one of our largest service territories.

Dennis M. Love, Chairman of the Board and Chief Executive Officer of Printpack Inc., which manufactures flexible and rigid packaging materials used primarily for consumer products, since 1987; currently a director of Oxford Industries, Inc.; and formerly a director of Caraustar Industries, Inc. Mr. Love, 60, has been a director of AGL Resources since October 1999.

Mr. Love's more than 28 years of experience as a chief executive officer brings key senior management and operational experience to our Board. Mr. Love's successful management and growth of his family-owned business to include international operations demonstrate his business strategy and acumen. His service on the nominating, compensation and governance committee of the board of directors of Oxford Industries also provides valuable insight on public company governance and compensation practices.

Dean R. O'Hare, former Chairman and Chief Executive Officer of The Chubb Corporation, a multi-billion dollar organization providing property and casualty insurance for personal and commercial customers worldwide, from 1988 until his retirement in November 2002; President of The Chubb Corporation from 1986 until 1988; Chief Financial Officer of The Chubb Corporation from 1980 until 1986; various other positions with increasing responsibility at The Chubb Corporation from 1963 until 1972; and formerly a director of Fluor Corporation and HJ Heinz Company. Mr. O'Hare, 73, has been a director of AGL Resources since August 2005.

As the former chief executive officer and chief financial officer of a Fortune 500 company with over 33 years of global business experience, Mr. O'Hare is a valuable member of our Board. Mr. O'Hare brings significant large public company operational, financial and corporate governance experience to our Board and his experience and relationships in one of our largest service territories provide key insight to our Board. Mr. O'Hare's extensive experience with the Chubb Corporation also brings valuable risk management experience to our Board.

Armando J. Olivera, former President and Chief Executive Officer of Florida Power & Light Company (FP&L), an electric utility services company with over $10 billion in annual revenue, from June 2003 until his retirement in May 2012; various other positions with increasing responsibility at FP&L from 1972 to 2003; currently a director of Fluor Corporation, Consolidated Edison and Lennar Corporation; and formerly a director of FP&L. Mr. Olivera, 66, has been a director of AGL Resources since December 2011 and was a director of Nicor from 2008 to 2011.

Mr. Olivera's experience in and understanding of utility regulation, operations and finance as well as his strong business leadership skills qualify him to serve on our Board. He has served in a leadership role on a number of electric utility industry groups including Chairman of the Florida Reliability Council, Chairman of the Association of Edison Illuminating Companies and President of the Southeastern Electric Exchange. He also has served in a number of community and educational organizations. He is currently a trustee of Miami Dade College and Cornell University and a director of Cornell Atkinson Sustainability Center.

John E. Rau, President and Chief Executive Officer of Miami Corporation, a private asset management firm, since December 2002; Chairman of Chicago Title and Trust Company Foundation, a charitable foundation, since March 2000; President and Chief Executive Officer of Chicago Title Corporation, a financial services corporation, from January 1997 to March 2000; currently a director of First Industrial Realty Trust, Inc. and BMO Financial Corp./BMO

Harris Bank, N.A.; and previously a director of BorgWarner Inc. and Wm. Wrigley Jr. Company. Mr. Rau, 67, has been a director of AGL Resources since December 2011, was a director of Nicor from 1998 to 2011 and Nicor’s lead director from 2006 to 2011.

Mr. Rau has served as chief executive officer at two major public companies and dean of Indiana University’s Kelley School of Business. Mr. Rau also has served in leadership roles at numerous business, civic and philanthropic organizations. He has authored several dozen nationally published essays and reviews and a book on the characteristics of successful chief executive officers. Mr. Rau’s strong leadership skills, his service on other boards of directors and his extensive knowledge of banking, finance, economics and real estate qualify him to serve on our Board. Mr. Rau’s prominent position in the Midwestern business community helps provide us with a wide variety of business insights and access to other business leaders.

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James A. Rubright, Non-Executive Chairman of our Board since January 2016; former Chairman and Chief Executive Officer of RockTenn Company (now WestRock Company), an integrated paperboard and packaging company, from 1999 until his retirement in October 2013; Executive Vice President of Sonat, Inc., an energy company, from 1994 until 1999; currently, the chairman of the board of directors of Forestar Group, Inc. and lead director of HD Supply Holdings, Inc.; and formerly a director of Avondale, Inc., Oxford Industries, Inc. and RockTenn Company.
Mr. Rubright, 69, has been a director of AGL Resources since August 2001 and serves as Lead Director since April 2015.
Mr. Rubright's experience on the board of directors of a variety of public companies along with his proven success as the chief executive officer of a large public company demonstrates his leadership capability and extensive knowledge of complex financial and operational issues that public companies face. In addition, his experience as a chief executive officer of a Fortune 500 company brings vital senior management experience and business acumen to our Board.
Mr. Rubright's extensive experience in the natural gas industry provides valuable insight to our Board. Mr. Rubright's background brings a deep understanding of operations and strategy with an added layer of risk management experience that is an important aspect of the composition of our Board.
Bettina M. Whyte, President of Bettina Whyte Consultants, LLC since July 2015; formerly Managing Director and Senior Advisor, Alvarez & Marsal Holdings, LLC, a leading independent global professional services firm, from January 2011 to July 2015; Chairman of the Advisory Board of Bridge Associates, LLC, a leading turnaround, crisis and interim management firm, from October 2007 until December 2010; Managing Director and Head of the Special Situations Group of MBIA Insurance Corporation, a world leader in credit enhancement services and a global provider of fixed-income asset management services, from March 2006 until October 2007; Managing Director of AlixPartners, LLC, a business turnaround management and financial advisory firm, from April 1997 until March 2006; Partner and National Director of Business Turnaround Services, Price Waterhouse LLP from 1990 until 1997; and currently a director of Amerisure Companies and WestRock Company (formerly RockTenn Company).
Ms. Whyte, 66, has been a director of AGL Resources since October 2004.
Ms. Whyte has vast experience in the financial and operational restructuring of complex businesses, and her service as interim chief executive officer, chief operating officer and chief restructuring officer of numerous troubled public and private companies is essential to our Board. Her experience on the board of directors of other public companies and her insight on financial and operational issues add value to our Board.
Henry C. Wolf, former Vice Chairman and Chief Financial Officer of Norfolk Southern Corporation, a holding company that controls a major freight railroad and owns a natural resources company and telecommunications company, from 1998 until his retirement in 2007; Executive Vice President- Finance of Norfolk Southern Corporation from 1993 until 1998; Vice President-Taxes of Norfolk Southern Corporation from 1991 until 1993; various other positions in the finance division with increasing responsibility at Norfolk Southern Corporation from 1973 until 1991; formerly a director of Hertz Global Holdings, Inc.; and currently serves as a trustee of Colonial Williamsburg Foundation. Mr. Wolf, 73, has been a director of AGL Resources since April 2004.
Mr. Wolf's unique professional background of over 43 years of experience with legal, financial, tax and accounting matters along with his demonstrated executive level management skills make him an important advisor. His skills are a vital asset to our Board at a time when accurate and transparent accounting, a sound financial footing and exemplary governance practices are essential. In addition, his background in strategic planning and experience with mergers and acquisitions in a regulated environment represent an important resource for us.
Section 16(a) Beneficial Ownership Reporting Compliance
Section 16(a) of the Exchange Act requires our directors and certain of our officers, including executive officers, and any person who owns more than 10% of our common stock to file reports of initial common stock ownership and changes in common stock ownership with the SEC and the New York Stock Exchange. Such persons are required by SEC regulations to furnish us with copies of all Section 16(a) forms that they file.
To our knowledge, based solely on our review of the copies of such reports received by us and written representations that no other reports were required for those persons during 2015, all filing requirements were met except, due to administrative constraint, Andrew W. Evans, Henry P. Linginfelter and Peter I. Tumminello each made a single late filing reporting a single transaction.

Ethics and Compliance Program

The Board is responsible for overseeing management's implementation of our ethics and compliance program to ensure that our business is conducted in a consistently legal and ethical manner. As part of the ethics and compliance program, we have established, and the Board has approved, our Code of Conduct and Ethics. Our Code of Conduct and Ethics governs the way we treat our customers and co-workers, guides our community interactions, and strengthens our commitment to excellence and integrity. The Code of Conduct and Ethics covers a wide range of professional conduct, including environmental, health and safety standards, employment policies, conflicts of interest, accuracy of records, fair dealing, insider trading and strict adherence to all laws and regulations applicable to the conduct of our business. Under the Code of Conduct and Ethics, employees are required to conduct our activities in an ethical and lawful manner and all employees are expected to report any situation where they believe our internal policies or external laws are being violated. Our Code of Conduct and Ethics applies to our directors, officers and all of our employees.

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In addition, the Board has adopted a Code of Ethics for the Chief Executive Officer and the Senior Financial Officers, or our Officers Code of Ethics, designed to deter wrongdoing and promote the following: honest and ethical conduct; full, fair, accurate, timely and understandable disclosure in documents filed with or submitted to the SEC; compliance with applicable governmental laws, rules and regulations; prompt internal reporting of violations of the Officers Code of Ethics; and accountability for adherence to the Officers Code of Ethics.

Any waiver of the Code of Conduct and Ethics or Officers Code of Ethics for an executive officer or, where applicable, for a member of the Board, requires the approval of the Board or a duly authorized committee of the Board and will be promptly disclosed on our website at www.aglresources.com.

The Board also has adopted Guidelines on Significant Corporate Governance Issues, or our Corporate Governance Guidelines, that set forth guidelines for the operation of the Board and its committees. The Board periodically reviews our governance practices and procedures, evaluating them against corporate governance best practices.

Our Code of Conduct and Ethics, our Officers Code of Ethics and our Corporate Governance Guidelines are available on our website at www.aglresources.com. They also are available to any shareholder upon request to our Corporate Secretary at AGL Resources Inc. at P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569.

Audit Committee

The Audit Committee met eight times during 2015. All members of the Audit Committee are independent, non-employee directors, as defined under the listing standards of the New York Stock Exchange and the Standards for Determining Director Independence as adopted by our Board. The Audit Committee's primary function is to assist the Board in fulfilling its oversight responsibilities. Among other things, the Audit Committee reviews (1) the integrity of our financial statements, including our internal control over financial reporting, (2) our compliance with legal and regulatory requirements, (3) the independent registered public accounting firm's qualifications and independence, (4) the performance of our internal audit function, and (5) the performance of the independent registered public accounting firm. Our chief financial officer, chief ethics and compliance officer, chief audit executive, chief accounting officer and representatives of our independent registered public accounting firm each provide a quarterly report to and meet in separate executive sessions with the Audit Committee each quarter.

The Board has determined that all members of the Audit Committee satisfy the enhanced independence standards applicable to all members of the Audit Committee under the independence requirements of the SEC, the New York Stock Exchange and our Standards for Determining Director Independence. The Board also has determined that all members of the Audit Committee meet the financial literacy requirements of the New York Stock Exchange listing standards. The Board has further determined that Sandra N. Bane, the Audit Committee Chair, is an "audit committee financial expert" within the meaning of SEC regulations. Information regarding Ms. Bane's qualification as an "audit committee financial expert" is included in her biographical information under the caption, "Directors of the Registrant."

The following directors served on the Audit Committee as of December 31, 2015: Sandra N. Bane (Chair), Norman R. Bobins, Brenda J. Gaines, Wyck A. Knox, Jr., Dennis M. Love, Dean R. O'Hare and James A. Rubright.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Committee Report

The Compensation Committee of the Board is composed of eight directors, each of whom is an independent director, as defined under the listing standards of the New York Stock Exchange and our Standards for Determining Director Independence. The Compensation Committee operates under a written charter adopted by the Board, a copy of which is available on our website at www.aglresources.com.

The Compensation Committee has reviewed and discussed with management the "Compensation Discussion and Analysis," or CD&A, section of this annual report on Form 10-K required by Item 402(b) of Regulation S-K promulgated by the SEC. Based on the Compensation Committee's review and discussions with management, the Compensation Committee recommended to the Board that the CD&A be included in this annual report on Form 10-K.

Members of the Compensation Committee:

Thomas D. Bell, Jr. (Chair)
Sandra N. Bane
Norman R. Bobins
Charles R. Crisp

Armando J. Olivera
James A. Rubright
Bettina M. Whyte
Henry C. Wolf

The information contained in the Compensation Committee Report shall not be deemed to be “soliciting material” or to be “filed” with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended, except to the extent that we specifically incorporate it by reference in such filing.

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Compensation Committee Interlocks and Insider Participation

The following directors served on the Compensation Committee during 2015: Sandra N. Bane, Thomas D. Bell, Jr. (Chair from April to December 2015), Norman R. Bobins, Charles R. Crisp, Armando J. Olivera, James A. Rubright, Bettina M. Whyte (Chair from January to April 2015) and Henry C. Wolf. None of such persons was, during 2015 or previously, an officer or employee of AGL Resources or any of its subsidiaries and each such person was an independent director as defined under the listing standards of the New York Stock Exchange and our Standards for Determining Director Independence. There were no Compensation Committee interlocks or insider participation in compensation decisions that are required to be disclosed in this annual report. None of the members of the Compensation Committee had any relationship requiring disclosure under Item 13, "Certain Relationships and Related Transactions and Director Independence" under the caption "Certain Relationships and Related Transactions."

Director Compensation

General A director who is our employee receives no additional compensation for his or her services as a director. A director who is not an employee (a non-employee director) receives compensation for his or her services as described in the following paragraphs. All directors are reimbursed for reasonable expenses incurred in connection with attendance at Board and committee meetings.

Annual Retainer Each non-employee director receives an annual retainer for service as a director on the first day of each annual service term. The amount and form of the annual retainer are fixed from time to time by resolution of the Board. For 2015, the annual retainer was $200,000, composed of the $95,000 Cash Portion and the $105,000 Equity Portion.

Although the Cash Portion of the annual retainer is typically payable in cash, a director may instead choose to receive the Cash Portion of the retainer in shares of the Company's common stock or to defer the Cash Portion of the retainer under the Common Stock Equivalent Plan. Similarly, although the Equity Portion of the annual retainer is typically payable in shares of our common stock, a director may choose to defer the Equity Portion of the retainer under the Common Stock Equivalent Plan.

The Equity Portion of the annual retainer paid in shares of our common stock is payable on the first day of the annual service term.

Amounts deferred under the Common Stock Equivalent Plan are invested in common stock equivalents that track the performance of our common stock and are credited with equivalents to dividend payments that are made on our common stock. Common stock equivalents may not be voted or transferred. At the end of a participating non-employee director's service on the Board, he or she receives a cash distribution based on the then-current market value of his or her common stock equivalents and dividend equivalents.

Non-employee directors do not receive additional compensation for attending Board or committee meetings.

Committee Chair Retainer Committee chairs receive an additional retainer on the first day of each annual service term. For 2015, the additional retainer for each committee chair was $15,000. A director can choose to receive the committee chair retainer in the form of cash or common stock, or to defer the retainer under the Common Stock Equivalent Plan.

Lead Director Retainer The lead director receives an additional retainer on the first day of each annual service term. For 2015, the additional retainer for the lead director was $25,000. The lead director retainer can choose to receive the lead director retainer in the form of cash or common stock, or to defer the retainer under the Common Stock Equivalent Plan.

2015 Non-Employee Director Compensation Paid The following table summarizes compensation earned and paid to or deferred by each non-employee director for service as a director during 2015.

2015 Non-Employee Director Compensation

Name	Fees Earned or Paid in Cash	Stock Awards [1]	All Other Compensation	Total
Sandra N. Bane [2][3]	$110,000	$105,000	$—	$215,000
Thomas D. Bell, Jr. [2]	110,000	105,000	—	215,000
Norman R. Bobins	95,000	105,000	—	200,000
Charles R. Crisp [2]	110,000	105,000	—	215,000

Brenda J. Gaines	95,000	105,000	—	200,000
Arthur E. Johnson (3)	95,000	105,000	—	200,000
Wyck A. Knox, Jr.	95,000	105,000	—	200,000
Dennis M. Love (4)	95,000	105,000	—	200,000
Dean R. O'Hare	95,000	105,000	—	200,000
Armando J. Olivera (3)	95,000	105,000	—	200,000
John E. Rau (2)(4)(5)	110,000	105,000	—	215,000
James A. Rubright (2)(6)	135,000	105,000	—	240,000
Bettina M. Whyte (3)(7)	95,000	105,000	—	200,000
Henry C. Wolf (4)	95,000	105,000	—	200,000

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(1) The aggregate grant date fair value of stock awards, which includes shares of our common stock and common stock equivalents, was computed in accordance with FASB ASC Topic 718 without regard to estimated forfeitures related to service-based vesting conditions. The assumptions used in calculating these amounts are incorporated by reference to Note 8 to our consolidated financial statements under Item 8 herein.
(2) Fees earned include a committee chair retainer of $15,000.
(3) This director elected to defer the Equity Portion of the annual retainer under the Common Stock Equivalent Plan.
(4) This director elected to receive the Cash Portion of the annual retainer in the form of stock.
(5) This director elected to receive the committee chair retainer in the form of stock.
(6) Fees earned include a lead director retainer of $25,000.
(7) This director elected to defer $20,000 of the Cash Portion under the Common Stock Equivalent Plan.

The aggregate number of stock awards, which includes shares of our common stock and common stock equivalents, for each of the non-employee directors outstanding at December 31, 2015, was as follows:

Name	Shares Outstanding	Common Stock Equivalents Outstanding (1)	Total Stock Awards Outstanding (1)
Sandra N. Bane	3,410	17,302	20,712
Thomas D. Bell, Jr.	32,558	—	32,558
Norman R. Bobins	12,565	—	12,565
Charles R. Crisp	16,739	14,589	31,328
Brenda J. Gaines	12,510	—	12,510
Arthur E. Johnson	4,338	52,113	56,451
Wyck A. Knox, Jr.	14,193	48,159	62,352
Dennis M. Love	41,937	42,169	84,106
Dean R. O’Hare	22,572	931	23,503
Armando J. Olivera	1,875	14,466	16,341
John E. Rau	25,080	—	25,080
James A. Rubright	22,235	26,230	48,465
Bettina M. Whyte	14,782	21,204	35,986
Henry C. Wolf	31,031	13,309	44,340

(1) Includes dividend equivalents.

Share Ownership and Holding Period Requirements for Non-Employee Directors In order to serve on our Board, directors are required to own shares of our common stock. Our share ownership guidelines for non-employee directors require that non-employee directors own shares of our common stock having a value of at least $475,000, which represents five times the value of the Equity Portion of the annual retainer. Each director has five years from the date of his or her initial election to meet the share ownership requirement. Common stock equivalents and shares issuable upon the exercise of vested stock options are included in the determination of the ownership guideline amount. We believe that the equity component of non-employee director compensation serves to further align the interests of our non-employee directors with the interests of our shareholders.

Under the terms of the Amended and Restated 2006 Non-Employee Directors Equity Compensation Plan (the 2006 Directors Plan), non-employee directors are required to hold shares awarded under such plan until the earlier of (i) five years from the date of the initial stock award or subsequent stock grant; (ii) termination of the non-employee director’s service; or (iii) a change in control of our company. Shares subject to the holding period include all shares issued in connection with the initial stock award under the plan and all shares issued under the plan in payment of all or part of a director’s annual retainer.

COMPENSATION DISCUSSION AND ANALYSIS

The following section contains a detailed description of our compensation objectives and policies, the elements of our compensation program, and the material factors the Compensation Committee considered in setting the compensation of our named executive officers for 2015, who are listed below:

Name	Title
John W. Somerhalder II	Former Chairman and Chief Executive Officer
Andrew W. Evans	President and Chief Executive Officer
Elizabeth W. Reese	Executive Vice President and Chief Financial Officer
Henry P. Linginfelter	Executive Vice President, Distribution Operations
Paul R. Shlanta	Executive Vice President, General Counsel and Chief Ethics and Compliance Officer
Peter I. Tumminello	Executive Vice President, Nonregulated Businesses and President Sequent

Mr. Evans served as our executive vice president and chief financial officer until May 6, 2015, when he was appointed as president and chief operating officer. At that time, Ms. Reese was promoted to the role of executive vice president and chief financial officer. Ms. Reese formerly served as our senior vice president and president of Nicor Gas, our largest gas distribution company. In addition, Mr. Tumminello, who has served as our executive vice president, wholesale services, and president of Sequent was promoted to executive vice president, nonregulated businesses, and was given responsibilities over retail operations in addition to wholesale services and midstream operations.

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Mr. Somerhalder retired as our chairman and chief executive officer effective December 31, 2015. Mr. Evans was promoted to president and chief executive officer and elected to our Board effective January 1, 2016.

Compensation Philosophy

Our compensation program is designed to reward employees for achieving our strategic and financial objectives; to attract, retain, motivate and reward top executive talent; and to foster long-term value creation for us and our shareholders. In support of this, our program is intended to:

- align executives' interests with those of our shareholders by creating a strong focus on stock ownership and basing pay on performance measures that are expected to drive long-term, sustained shareholder value growth;
- include a strong link between pay and performance by placing a significant portion of compensation "at risk" based on corporate and business segment performance;
- assure our access to top executive talent and protect against competitor recruitment through compensation opportunities that are market competitive and commensurate with the executives' responsibilities, experience and demonstrated performance; and
- reinforce our business strategies and reflect our core values by rewarding desired performance, promoting desired competencies and recognizing contributions to business success that are consistent with those core values.

How We Tie Pay to Performance

Our executive compensation program contains three elements of total direct compensation: base salary, annual incentive, and long-term equity awards. Our program is structured so that a significant portion of target total direct compensation depends upon our achievement of certain goals and targets related to financial and operational performance, and our total shareholder return relative to our peer group. We believe these performance criteria strengthen the alignment between executive pay and value-creation for our shareholders.

Our annual incentive awards, which are paid in cash, are conditioned upon our achievement of pre-established performance goals. Annual incentive awards for Messrs. Somerhalder, Evans, Linginfelter and Shlanta and Ms. Reese were based upon achievement of an adjusted earnings per share goal, which we call "Plan EPS," and business segment goals. Mr. Tumminello's annual incentive award was based primarily on adjusted pre-bonus accrual EBIT, which we call "Plan Earnings," of Sequent, our wholesale services segment, with a smaller component based on the performance of midstream operations (storage and fuels).

Our long-term equity awards consist of performance-based restricted stock units (RSUs), which require achievement of an annual earnings before interest, taxes, depreciation and amortization (EBITDA) target, and performance share units (PSUs), which are earned based on our adjusted cumulative earnings per share, excluding wholesale services, which we call "Cumulative Core EPS," and our total shareholder return relative to our peer group over a period of three years (RTSR).

A significant portion of target total direct compensation for each of our named executive officers in 2015 was based on corporate or business segment performance requirements.

2015 Performance Highlights In 2015, we achieved solid financial results that surpassed our full-year expectations. Excluding merger-related expenses and a goodwill impairment charge, we generated net income from continuing operations of $388 million and diluted EPS of $3.24.

In March 2015, we raised our 5-year compound annual EPS growth rate forecast to a range of 6% to 9% (increased from the previous range of 4% to 6% annually), which is among the highest targeted growth rates in our sector. We raised our forecast as the result of continued investment in our regulated utilities and our nearly $700 million of planned investment in interstate pipelines with long-term contracts.

In August 2015, we announced our agreement to be acquired by Southern Company for $66 per share. The transaction represents a 36% premium to the volume-weighted average stock price over the 20 days prior to the announcement date, and led to total shareholder return for the year of 20%. Our total shareholder return for the three-year period ended December 31, 2015 was 74%.

We increased our annual dividend to shareholders by 4.1%, from an indicated annual dividend of $1.96 per share to $2.04 per share, continuing our demonstrated track record of returning value to shareholders through annual dividend increases.

2015 Performance and Compensation Reflecting our pay-for-performance compensation philosophy, the compensation of our named executive officers was directly affected by our financial results in 2015, both with respect to the amount of annual incentive and long-term equity awards earned and the underlying value of long-term equity awards.

Annual Incentive Awards Our 2015 annual incentive awards were based upon a combination of several goals:

- Corporate Plan EPS (described under the caption "Annual Incentive Awards - Corporate Measure"),
- EBIT, safety and customer service metrics for our regulated business segment (distribution operations) (described under the caption "Annual Incentive Awards - Business Segment Measures"), and
- EBITDA metrics for our non-regulated business segments (described under the caption "Annual Incentive Awards - Business Segment Measures").

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As noted above, 2015 was a successful year for us. We met the Plan EPS hurdle and exceeded the target goals and maximum "affordability factor" under the annual incentive plan. The named executive officers, other than Mr. Tumminello, earned an annual incentive plan payout for 2015 ranging from 183.3% to 184.4% of target. Please see the discussion of these awards under the heading "Annual Incentive Awards."
We provide a separate annual incentive program for Mr. Tumminello, who serves as president of Sequent and leads our wholesale services segment and our storage and liquefied natural gas/fuels (storage and fuels) operations in our midstream operations segment. Mr. Tumminello's annual incentive is primarily based upon Sequent's Plan Earnings, with a smaller component based on the performance of midstream operations (storage and fuels). Based upon 2015 performance, Mr. Tumminello received an incentive plan award of $2,094,870, of which $835,619 was deferred for payout over a 24-month period in accordance with a mandatory retention provision in his program. A description of Mr. Tumminello's incentive program is included under the caption "Annual Incentive Award for Mr. Tumminello."
Long-Term Incentive Awards In 2015, we continued to grant performance-based RSU's (representing 30% of each executive's target long-term incentive value) and PSUs (representing 70% of each executive's target long-term incentive value). The RSU's include a one-year EBITDA hurdle and a four-year ratable time-based vesting schedule. Because we met the EBITDA hurdle, 25% of the RSUs granted in 2015 were vested and the remainder of the awards converted to time-vesting restricted stock for the remaining three years of the vesting period.
The PSUs are earned based upon a combination of Cumulative Core EPS over a three-year period (weighted at 25%) and our RTSR over a three-year period, compared to a peer group consisting of 12 comparable companies (weighted at 75%). The performance period for the PSUs granted in 2015 will be completed at the end of 2017. Please see the discussion of the calculation of RTSR and Cumulative Core EPS on the previous page under this caption.
The PSUs granted in 2013, which had a three-year performance period that ended December 31, 2015 and were based solely on RTSR, were earned at 145% of target because our RTSR was at the 72.7th percentile ranking relative to our peer group for that period. Please see the discussion of the long-term incentive awards on the previous page under this caption.
Continuity Agreements Each of our executives has a continuity agreement that provides severance pay if the executive's employment is terminated in certain circumstances in connection with a change in control. The agreements have a double-trigger provision, which means that severance benefits are not provided unless both (i) a change in control occurs and (ii) the executive incurs a qualifying termination within a designated period of time. The August 24, 2015 announcement of the proposed merger with Southern Company triggered the coverage period for these agreements, and their terms automatically extended so that they will remain in place until the second anniversary of the closing of the proposed merger with Southern Company unless the merger is abandoned. The continuity agreements are described under the caption "Continuity Agreements."
Limited Perquisites As in prior years, the only perquisite that we offer our executives is reimbursement for mandatory tax return preparation. To the extent that the entire authorized amount is not used for tax preparation, it may be applied to financial or estate planning.
Changes in Compensation Program for 2015. As part of its ongoing effort to enhance and refine our compensation program, the Compensation Committee made several important changes for the named executive officers for 2015:

- Effective February 23, 2015, base salaries were increased by 3% for each of the named executive officers, which was consistent with increases for other salaried employees.

Two changes were made to the business performance component for the annual incentive program for 2015:

- The financial measure for our distribution operations business segment was changed from margin (weighted at 20%) to EBIT (weighted at 36%). The Compensation Committee considers EBIT to be more closely correlated to distribution operations' achievement of its allowed return and to the manner in which the business segment is managed, by focusing on customer margins, operations and maintenance expense, and depreciation (including capital deployment management).
- The performance measure relating to operations and maintenance expense less benefits and incentives for each named executive officer was eliminated because expense management is incorporated in the new EBIT measure. The Compensation Committee also believes that focus on EBIT aligns the goals more closely to the performance of the business segment.

The PSUs granted in 2015 continue to include a goal relating to our RTSR over a three-year period, compared to a peer group consisting of 12 comparable companies, but this measure is now weighted at 75% instead of 100%. The Compensation Committee established an additional measure for these awards, weighted at 25%, relating to our Cumulative Core EPS over the three-year performance period. We believe that Cumulative Core EPS is a direct contributor to shareholder value. The RTSR calculation uses a 20-day average share price when determining the opening and closing share prices, excluding any company that announces that it is being acquired.
In recognition of the new leadership appointments on May 6, 2015, and their new and expanded roles, the following additional changes were made to the compensation programs for Messrs. Evans and Tumminello and Ms. Reese:

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- Mr. Evans' base salary was increased to $700,000, with a target annual cash incentive of 80% of base salary and a target long-term incentive award opportunity of $1,750,000.
- Ms. Reese's base salary was increased to $440,000, with a target annual cash incentive of 65% of base salary and a long-term incentive award opportunity of 160% of base salary.
- Mr. Tumminello's base salary was increased to $430,000, his annual cash incentive remained unchanged and linked to Sequent's Plan Earnings, with a smaller component based on the performance of midstream operations (storage and fuels), and his long-term incentive award opportunity remained unchanged at 75% of base salary.

Governance and Evolving Compensation Practices

The Compensation Committee and our management are mindful of evolving practices in executive compensation and corporate governance. In response, we have adopted certain policies and practices that are in keeping with best practices in many areas. For example:

- We do not provide excessive executive perquisites or extraordinary relocation benefits to our named executive officers.
- We do not provide tax gross-ups on compensation paid to our named executive officers, or on "golden parachute" excise taxes.
- Our Omnibus Performance Incentive Plan (OPIP) has double-trigger vesting for equity awards in the context of a change in control if the awards are assumed by the acquiring company.
- Our OPIP expressly prohibits repricing of options (directly or indirectly) without prior shareholder approval.
- The Compensation Committee engages an independent compensation consultant.
- Our stock ownership policy requires that each executive must retain at least 75% of net shares from his or her equity awards until the ownership requirement is met.
- Our policy prohibits directors and executive officers from engaging in hedging activities involving our stock.
- Our policy requires the recovery of certain incentive-based compensation paid to current or former executive officers in the event of an accounting restatement.

Say on Pay Results and Consideration of Shareholder Support

At the annual meeting of shareholders on April 28, 2015, over 96% of the votes cast were in favor of the advisory vote to approve executive compensation. The Compensation Committee considered this positive result and concluded that the shareholders continue to support the compensation paid to our executive officers and our overall pay practices.

In light of this support, the Compensation Committee decided to retain the core design of our executive compensation program for 2015, with an emphasis on short and long-term incentive compensation that rewards our senior executives when they successfully implement our business plan and, in turn, deliver value for our shareholders.

The Compensation Committee will continue to monitor best practices, future advisory votes on executive compensation and other shareholder feedback to guide it in evaluating the alignment of our executive compensation program with our interests and the interests of our shareholders. The Compensation Committee invites our shareholders to communicate any concerns or opinions on executive pay directly to the Board. Shareholders and other interested parties may communicate with our Board or, alternatively, with the presiding director of executive sessions of our non-management directors or with the non-management directors as a group via our Ethics and Compliance Helpline at (800) 350-1014 or at www.mycompliancereport.com. A copy of our Procedures for Communicating with the Board is available on our website at www.aglresources.com and is available in print to any shareholder who requests it from our Corporate Secretary at AGL Resources Inc., P.O. Box 4569, Location 1466, Atlanta, Georgia 30302-4569.

Based upon the preference expressed by our shareholders at the 2011 annual meeting, the Board has implemented an annual advisory vote on executive compensation. The next required vote on the frequency of shareholder votes on executive compensation would occur at the 2017 annual meeting.

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How We Make Compensation Decisions

The Compensation Committee oversees our executive compensation program. The Compensation Committee engages the services of Frederic W. Cook & Co., Inc. (FW Cook), an independent consultant. FW Cook reports directly to the Compensation Committee and provides no other services to us. The following table outlines the roles and responsibilities of various parties in determining executive compensation.

Parties	Roles and Responsibilities
Compensation Committee	• Approves incentive programs and sets performance goals.
	• Determines appropriate levels of compensation for our executives, other than our chief executive officer.
	• Recommends to independent Board members compensation opportunities and awards for our chief executive officer.
	• Provides a competitive assessment of our executives' compensation levels and programs.
FW Cook	• Provides advice, research and analytical services on a variety of subjects, including compensation trends, best practices, peer group comparisons and the compensation of our non-employee directors.
Independent directors on full Board	• Evaluates chief executive officer performance.
	• Approves compensation for our chief executive officer.
Chief executive officer	• Develops an assessment of individual performance for each other named executive officer.
	• Provides recommendations to the Compensation Committee regarding individual compensation levels for such executives.
	• Provides recommendations to the Compensation Committee regarding goals for the performance measures in the incentive plans.
Other members of management	• Our human resources staff provides data and information relating to our compensation programs to the Compensation Committee and FW Cook to help facilitate the Compensation Committee's review of competitive compensation practices.
	• Our chief financial officer provides the Compensation Committee with reports on financial performance as it relates to key business drivers and performance measures included in incentive program designs.

Competitive Market Information Each year the Compensation Committee works with FW Cook to review the market competitiveness of our executive compensation programs and levels and to re-evaluate the companies included in our comparator groups to ensure that we have the appropriate marketplace focus. For 2015, FW Cook prepared a competitive assessment of our executives' base salaries, target annual incentive awards, and long-term incentive opportunities, against an "energy industry database" and an "executive compensation peer group."

Energy Industry Database For 2015, the energy industry database included energy services companies in Towers Watson's CDB Energy Services Executive Compensation Survey Report - U.S. with assets or revenue between one-third and three times ours. This group was used as the primary source to assess competitive levels of compensation for our executives. We believe this larger selection of companies provides more accurate and reliable information than a smaller peer group and better reflects the labor market for our executive talent.

For 2015, the following 43 companies were included in our energy industry database:

The AES Corporation
Alliant Energy Corporation
Ameren Corporation
American Electric Power Company
Atmos Energy Corporation
Calpine Corporation
CenterPoint Energy, Inc.

CMS Energy Corporation
Consolidated Edison, Inc.
Dominion Resources Inc.
DTE Energy Company
Edison International
Energen Corporation
Entergy Corporation
First Solar, Inc.
FirstEnergy Corp.
IDACORP, Inc.
Integrys Energy Group, Inc.
MDU Resources Group, Inc.
NextEra Energy, Inc.
New Jersey Resources Corp.
NRG Energy Inc.

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NiSource Inc.
Northeast Utilities
OGE Energy Corp.
Pepco Holdings, Inc.
PG&E Corp.
Pinnacle West Capital Corporation
PNM Resources, Inc.
Portland General Electric Company
PPL Corporation
Public Service Enterprise Group Incorporated
SCANA Corporation
Sempra Energy
Southwest Gas Corporation
Spectra Energy Corp.
TECO Energy, Inc.
UGI Corporation
UIL Holdings Corporation
Vectren Corporation
Westar Energy, Inc.
Wisconsin Energy Corporation
Xcel Energy Inc.

Executive Compensation Peer Group In 2015, we also reviewed compensation data for 12 natural gas providers as a secondary point of reference. The companies in this executive compensation peer group were selected based upon their size and business operations. With assistance from FW Cook, the following criteria were developed for this group:

Size Requirements	Industry Requirements
Must be roughly one-third to three times our size in at least two of the following categories:	Must be a traditional natural gas local distribution company and must meet at least one of the following:
• assets;	• includes non-regulated businesses such as storage, pipeline or construction services;
• revenue; or	• includes asset management/trading business similar to Sequent; or
• market capitalization	• conducts business in three or more states

For 2015, the following 12 companies were included in our executive compensation peer group:

Atmos Energy Corporation
CenterPoint Energy, Inc.
Laclede Group, Inc.(1)
New Jersey Resources Corporation
NiSource Inc.
ONE Gas, Inc.
Piedmont Natural Gas Company Inc. (1)
Sempra Energy
Southwest Gas Corporation
UGI Corporation
Vectren Corporation
WGL Holdings, Inc.

(1) At the time the peer group was approved, Laclede and Piedmont did not meet all three size requirements, but the Compensation Committee decided to include these companies due to overall similarities in business

characteristics with us.

To perform a more meaningful analysis of Mr. Tumminello’s compensation as the president of Sequent, FW Cook used the Towers Watson Energy Trading and Marketing Survey, which included data more directly comparable to Mr. Tumminello’s position. This survey data included the following companies having energy trading and marketing operations:

Atmos Energy Corporation
BP
Cargill
CenterPoint Energy, Inc.
Chevron
Constellation Energy
Dominion Resources Inc.
EDF Trading

Iberdrola Renewables, Inc.
Nexen, Inc.
NRG Energy
Occidental Petroleum
ONEOK, Inc.
PPL Corporation
Williams Energy Services

Compensation Elements and their Purpose

Our executive compensation program includes the following elements.

Compensation Element	Overview/Objectives
Base salary	• Fixed portion of an executive's annual compensation; is intended to recognize fundamental market value for the skills and experience of the individual relative to the responsibilities of his or her position. • Foundation of our program; most other elements are determined as a percentage of base salary.
Annual incentive award (1)	• Annual cash incentive award is intended to vary as a direct reflection of corporate and business segment performance. • Target opportunities are a percentage of base salary and represent the amount of money to be paid if expected performance is achieved. • Achievement of a performance hurdle based on Plan EPS is required for any payout. • Performance measures include Plan EPS for corporate performance and a combination of EBIT and safety and customer service measures for business segment performance. • Payouts are subject to reduction pursuant to an affordability factor based on the performance of distribution operations against an EBIT target. • Actual awards may range between 0% and 200% of target, based on performance against goals. • To achieve a 200% award, performance must meet or exceed the maximum performance levels for all performance measures, including the affordability factor.
Long-term incentive awards (RSUs and PSUs)	• Stock-based incentives reward performance over a multi-year period, link executives' interests to those of shareholders, and encourage retention. • Performance measures include EBITDA achievement for performance-based RSU's and, for PSUs, Cumulative Core EPS and total shareholder return relative to the performance of the executive compensation peer group, over a three-year period. • Vesting schedules serve to encourage retention and further tie an executive's compensation to stock price appreciation during the vesting period.
Employee health and welfare and retirement benefit plans	• Competitive levels of medical, retirement and income protection, such as life and disability insurance coverage, are provided. • Executives participate in the same programs offered to all of our eligible employees. • To maintain consistent retirement benefit levels, we also provide non-qualified retirement benefits to executives and other highly-compensated employees who are adversely affected by tax limits imposed on contributions and total benefits under our retirement plans.
Severance and other termination payments	• Severance benefits are provided in the event an executive's employment is terminated in certain circumstances in connection with a change in control. • Agreements provide security to executives so that they may focus on business objectives and the best interests of our shareholders during a transaction or potential transaction.
Financial planning / tax return preparation	• We reimburse executives for up to $18,000 per year for tax return preparation. We require professional tax return preparation as a means of ensuring tax compliance by

perquisite	our executives. To the extent that the entire amount is not used for tax preparation, the remainder may be applied to financial or estate planning.

(1) Mr. Tumminello's incentive program is described under the caption "Annual Incentive Award for Mr. Tumminello."

Setting 2015 Total Direct Compensation Opportunities

When setting base salary and target amounts for annual and long-term incentives, the Compensation Committee examined each component of pay on both a stand-alone basis and as a total. For the chief executive officer role, the Compensation Committee provided recommendations to the Board regarding base salary, target annual incentive opportunity and target long-term incentive opportunity.

Pay decisions were based on the Compensation Committee's business judgment, informed by the comparative data, professional advice and other considerations, including the individual executive's experience and performance, internal pay equity and mastery of position responsibilities. As in prior years, target annual and long-term incentive values were set as a percentage of base salary for each of our named executive officers, other than Mr. Somerhalder's and Mr. Evans' target long-term incentive, which were set as a specific amount, and Mr. Tumminello's target annual incentive, which was largely based on Plan Earnings of Sequent, with a smaller component based on the performance of midstream operations (storage and fuels).

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Fiscal 2015 Target Compensation Elements

Name	Base Salary	Target Annual Incentive ($ or % of Base Salary)		Target Long-Term Incentive ($ or % of Base Salary)	
John W. Somerhalder II	$1,004,216	110	%	$3,500,000	
Andrew W. Evans	700,000	65%/80% (prorated)		184%/$1,750,000 (prorated)	
Elizabeth W. Reese	440,000	45%/65% (prorated)		65%/160% (prorated)	
Henry P. Linginfelter	563,705	65	%	160	%
Paul R. Shlanta	462,617	55	%	120	%
Peter I. Tumminello	430,000	$537,500		75	%

In connection with their promotions on May 6, 2015, Mr. Evans' base salary was increased from $576,221 to $700,000, Ms. Reese's base salary was increased from $333,385 to $440,000 and Mr. Tumminello's base salary was increased from $376,991 to $430,000. In addition, as reflected in the table above, Mr. Evans' and Ms. Reese's target annual incentive and target long-term incentive were increased and were applied on a pro rata basis based on their time in each position during 2015. As a result of these changes, additional long-term incentive awards were issued to Messrs. Evans and Tumminello and Ms. Reese on May 28, 2015.

Base Salaries

Each of the named executive officers received a 3% increase in base salary, effective February 23, 2015. In determining base salary, the Compensation Committee considered competitive market base pay levels, as reflected in the competitive data provided by FW Cook, the Board's general assessment of the performance of our chief executive officer, and the performance assessments and recommendations for the other named executive officers as presented to the Compensation Committee by our chief executive officer. Performance assessments for base salary were subjective and non-formulaic and were not based upon any specific financial criteria.

In connection with their promotions on May 6, 2015, which are described at the beginning of CD&A, Messrs. Evans and Tumminello and Ms. Reese receive based salary increases, as reflected in the table above.

Annual Incentive Awards

Performance Hurdle Our annual incentive program is a subplan of our OPIP, which was approved by shareholders in 2011. Each of the named executive officers participates in the annual incentive program. Mr. Tumminello's incentive program is different than the program for the other named executive officers and is described separately under the caption "Annual Incentive Award for Mr. Tumminello."

For 2015, we continued the practice of utilizing a performance hurdle for our annual incentive program so that awards may qualify as performance-based compensation under Code Section 162(m). Achievement of the performance hurdle allows the Compensation Committee to fund the program up to the maximum payout level established for each award, or to provide for a lesser amount based upon the annual performance goals approved by the Compensation Committee, which are described below. Achievement of the performance hurdle is required for any funding of the annual incentive program for the executive officers. The performance hurdle approved by the Compensation Committee for 2015 was Plan EPS of $2.84. The method of determining Plan EPS is described below under the caption " Annual Incentive Awards - Corporate Measure."

Weighting of Executive Performance Goals The performance measures for the 2015 annual incentive awards were derived from our annual operating plan and business strategy. The Compensation Committee approved a uniform weighting of goals for the named executive officers (other than Mr. Tumminello) as follows:

- 60% corporate performance, measured by Plan EPS and described below; and
- 40% business segment performance, measured as described below.

1. Corporate Measure The annual incentive plan uses a corporate performance measure that is described under the caption "How We Tie Pay to Performance," which we refer to as Plan EPS. While EPS is a commonly understood metric, the Compensation Committee views EPS determined in accordance with GAAP as not accurately reflecting the value we created during a particular year with respect to our wholesale services segment (Sequent). For compensation purposes, we seek to consider and measure the economic value for the period in which it is generated,

regardless of the period in which it is reported under GAAP. The method of determining 2015 Plan EPS was approved by the Compensation Committee at the time the performance goals were established.
In accordance with this method, when calculating 2015 Plan EPS, we started with GAAP EPS and subtracted the value created and credited for compensation purposes in 2014 which was expected to be reported in future periods, including 2015. We then added the value created and credited for compensation purposes in 2015 that will be reported on a GAAP basis in future periods. This was accomplished by adjusting for the economic value associated with Sequent's storage and transportation positions.

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At the time performance goals were established, the Compensation Committee also provided that 2015 Plan EPS would exclude the following:

- the effect of non-cash losses, including asset or goodwill impairment charges and loss on the sale of assets or subsidiaries;
- transaction costs associated with business combinations and related integration costs;
- changes in estimates or adjustments to actual settlement amounts equal to $100,000 or more related to legal issues existing at and prior to the closing date of an acquisition; and
- adjustments resulting from changes in GAAP.

For 2015, the Compensation Committee approved a Plan EPS "target" amount of $3.04, which would result in a 100% payout of the corporate component. This target amount:

- was based on an amount equal to $2.76 per share for 2015, consistent with the 2015 consolidated EPS budget approved by the Board, plus an adjustment to add $0.28 of expected EPS value to be generated by Sequent during 2015;
- was expected to be an appropriate target when considering our 2015 business objectives; and
- took into consideration the anticipated volatility and treatment of earnings from Sequent.

The Compensation Committee also approved a "threshold" Plan EPS of $2.94, which was required to be met before any corporate performance component could be earned. At threshold performance, the corporate component would pay out at 50%.

Below threshold performance, no corporate component would be paid, but as long as the $2.84 Plan EPS performance hurdle was met, the business performance components would be eligible to pay out based on actual business segment outcomes.

As shown in the table below, actual Plan EPS for 2015 was $3.44, which is above both the performance hurdle and the threshold goal set for 2015. Accordingly, the named executive officers earned a payout related to the corporate performance component and the business segment component.

2015 Corporate Measure - Goals and Results

	Performance Hurdle 162(m) Qualifier	Threshold (50%)	Target (100%)	150%	Maximum (200%)	Actual Plan EPS
GAAP EPS [1]	$2.56	$2.66	$2.76	$2.86	$2.96	$2.94
Adjusted for the net economic value generated by wholesale services to be recognized on a GAAP basis in future periods	0.28	0.28	0.28	0.28	0.28	0.20
Adjusted for goodwill impairment, merger-related expenses and change in a pre-Nicor acquisition legal reserve	—	—	—	—	—	0.30
Plan EPS	$2.84	$2.94	$3.04	$3.14	$3.24	$3.44

(1) Diluted EPS from continuing operations attributable to AGL Resources Inc.

2. Business Segment Measures The business performance component of the annual incentive plan uses performance measures and key operating metrics for the following regulated and non-regulated business segments:

Regulated	Non-Regulated
	Wholesale services
Distribution operations	Retail operations
	Midstream operations

These performance measures and metrics, which are described in more detail below, accounted for the entire business performance component under the annual incentive plan for each of the participating named executive officers in 2015.

For 2015, the Compensation Committee approved the same weighting of the business segment categories (regulated and non-regulated) for each of the participating named executive officers, other than for Mr. Linginfelter, our executive vice president, distribution operations, whose business segment goals remain focused on the regulated business.

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2015 Business Performance Measure - Goals and Weightings

Name	Regulated Segment (Distribution Operations) (1)	Non-Regulated Segments (2)	Total
John W. Somerhalder II	75 %	25%	100%
Andrew W. Evans	75 %	25%	100%
Elizabeth W. Reese	75 %	25%	100%
Henry P. Linginfelter	100 %	—	100%
Paul R. Shlanta	75 %	25%	100%

(1) Performance for the regulated segment was based on composite results.
(2) Performance for the non-regulated segments was weighted as follows:

Non-Regulated Business Segment Weightings	
Wholesale services	45%
Retail operations	45%
Midstream operations	10%

Business performance measures for our regulated segment were based upon EBIT goals (36%) and specific metrics relating to safety (32%) and customer service (32%). In addition, these measures were multiplied by an "affordability factor" that would serve to reduce the payout level if the business segment's EBIT was less than $575 million, with results interpolated on a straight line basis between the following performance levels:

Distribution Operations Performance (EBIT) - Affordability Factor

EBIT	< $535 million	$535 million	$555 million	$575 million
Affordability Factor (level of funding)	—	50%	75%	100%

Because distribution operations was expected to contribute approximately 75% of our EBIT for 2015, the affordability factor served to ensure a level of earnings contribution from distribution operations that we believed was appropriate to fund any of the business performance measures. Accordingly, the affordability factor was applied to both the regulated and non-regulated business segments.

Business performance measures for our non-regulated businesses were based upon EBITDA for each business segment. The non-regulated business measures did not include a separate affordability factor because the performance measures already include EBITDA targets. However, as described above, the funding of the non-regulated business segment measures was dependent upon the EBIT performance of distribution operations and the corresponding affordability factor.

Business performance goals, derived from the budget approved by the Board, were determined for each named executive officer, other than Mr. Tumminello, including a threshold, below which no award would be provided, a target amount, and a maximum award of 200%. These performance ranges were set in a qualitative, non-formulaic manner, based upon a combination of historical performance and our expected performance for 2015. The performance for each business performance goal was measured independently and combined based on the weightings described above to determine a final business performance score. The following table reflects the payout percentage at different performance levels.

	Business Performance Score Achieved	Payout % (1)
Minimum	50%	0%
	60%	20%
	70%	40%
	80%	60%
	90%	80%
Target	100%	100%
	110%	120%
	120%	140%
	130%	160%
	140%	180%

Maximum	150%	200%

(1) As noted above, the final payout amount for the business performance component for each named executive officer, other than Mr. Tumminello, was conditioned on the $2.84 Plan EPS performance hurdle being met and was subject to the affordability factor based on EBIT of distribution operations.

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Review of Awards The Compensation Committee reserves the right to adjust performance objectives during the course of the year in order to reflect changes in our business. In determining the corporate performance components under our OPIP, the Compensation Committee has the authority to: (i) exclude extraordinary one-time effects, which could increase or decrease award payments, if, in its business judgment, our shareholders are better served by that result; and (ii) exercise negative discretion against reported results which would serve to reduce an award otherwise due.

For 2015, the Compensation Committee did not exercise discretion in connection with the calculation of any performance goals or amounts.

Annual Incentive Performance Composite Results The following table provides the aggregate weighted result of all performance measures (corporate and business segment) for each of the named executive officers, other than Mr. Tumminello. This amount was multiplied by the executive's target opportunity (expressed as a percentage of eligible earnings as defined in the plan document) to determine the actual amount earned.

2015 Annual Incentive Award - Composite Performance and Results

Name	Corporate Payout Percentage (60% weighting)	Business Segment Payout Percentage (40% weighting)	Total Payout Percentage	2015 Target Opportunity (% of Base Salary)	2015 Annual Incentive Payout
John W. Somerhalder II	200%	160.77%	184.3%	110%	$2,024,521
Andrew W. Evans (1)	200%	160.77%	184.3%	80%	$895,370
Elizabeth W. Reese (2)	200%	160.80%	183.3%	65%	$420,659
Henry P. Linginfelter	200%	160.90%	184.4%	65%	$671,721
Paul R. Shlanta	200%	160.77%	184.3%	55%	$466,323

(1) The annual incentive award for Mr. Evans was prorated between a target of 65% for his prior position as executive vice president and chief financial officer and a target of 80% for his position as president and chief operating officer.

(2) The annual incentive award for Ms. Reese was prorated between a target of 45% for her prior position as president of Nicor Gas and a target of 65% for her position as executive vice president and chief financial officer. In Ms. Reese's prior position, there was also an individual performance component (weighted at 15%), in addition to the corporate component (weighted at 50%) and the business performance component (weighted at 35%).

Annual Incentive Award for Mr. Tumminello

For 2015, Mr. Tumminello's annual incentive award primarily was based on Plan Earnings for wholesale services, as described below. This is consistent with our philosophy of placing greater emphasis upon the cash compensation of members of our wholesale services segment. As president of Sequent, Mr. Tumminello was eligible to receive an amount under our OPIP equal to 9.375% of an incentive pool established for employees of Sequent under the Sequent Incentive Plan (Sequent Plan), calculated as if he were an actual participant in the Sequent Plan. The first 8.125% of the incentive pool under the Sequent Plan is regarded as "target" performance, and the remaining 1.25% may be earned based on Mr. Tumminello's individual performance as assessed by our chief executive officer and approved by the Compensation Committee.

The Sequent incentive pool was funded based on a pre-determined formula. The 2015 pool funded at a rate of 12% of Sequent's Plan Earnings. When calculating Sequent's 2015 Plan Earnings, we started with Sequent's pre-bonus accrual EBIT, adjusted for its interest expense for 2015 and the December 31, 2014 rollout value associated with storage and transportation hedges, added the December 31, 2015 rollout value associated with storage and transportation hedges, and adjusted for other items, as defined by the plan and consistent with historical practice. At the time performance goals were established, the Compensation Committee also provided that for purposes of calculating the Plan Earnings for Mr. Tumminello's annual incentive award, any one-time, non-recurring items under GAAP arising during 2015 would be excluded, and Sequent's 2015 Plan Earnings would exclude the same items excluded in the calculation of

Plan EPS, as described under the caption "How We Tie Pay to Performance."
Similar to prior years, the Compensation Committee authorized an additional incentive for Mr. Tumminello, which he was eligible to earn based upon the 2015 EBITDA performance of midstream operations (storage and fuels), which he oversees. The target payout amount was $50,000 (with up to $100,000 maximum payout amount), and was conditioned upon achievement of the performance hurdle of $2.84 Plan EPS.
For 2015, Sequent’s Plan Earnings were $177.3 million, which after adjustment resulted in the funding of an incentive pool of approximately $21.3 million. Mr. Tumminello’s annual incentive payout amount was $2,094,870 and was calculated as follows:

2015 Annual Incentive Award for Mr. Tumminello - Composite Performance and Results	
8.125% of Sequent Pool	$1,728,887
Individual Performance	265,983
Midstream Operations Performance (Storage and Fuels Component)	100,000
Total Incentive Award	$2,094,870

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The Sequent Plan provides that if Mr. Tumminello's annual incentive award exceeds his eligible earnings, then 50% of the overage is subject to mandatory deferral. Under this mandatory deferral provision, one half of the deferred amount is paid 12 months after the initial incentive payment, and the other half is paid 24 months after the initial payment. This deferral feature is intended to act as a retention vehicle. Of Mr. Tumminello's 2015 incentive award, a total of $835,619 was deferred for payout over 24 months.

Though not subject to an absolute maximum, the size of the Sequent Plan incentive pool, and correspondingly Mr. Tumminello's annual incentive award, is constrained by a framework of established risk parameters including open position limits, value-at-risk limits, stop-loss limits, and credit limits. The Compensation Committee has reviewed management's analysis of the Sequent Plan and determined that because of the operational limits on Sequent and our risk management oversight, the Sequent Plan does not incent excessive risk taking.

Long-term Incentive Awards

Two types of long-term incentive grants were awarded in 2015. RSUs (representing 30% of each executive's target long-term incentive value) and PSUs (representing 70% of each executive's target long-term incentive value) were selected based on the following factors:

- the impact each type of award has on shareholder value creation and executive motivation and retention;
- competitive practice; and
- balancing the cost of equity awards and the projected impact on shareholder dilution.

The target long-term incentive amount for each of the named executive officers is reflected in the Fiscal 2015 Target Compensation Elements table under the caption "Setting 2015 Total Direct Compensation Opportunities." As noted above, in connection with their promotions on May 6, 2015, and the related changes to their compensation, additional long-term incentive awards were issued to Messrs. Evans and Tumminello and Ms. Reese on May 28, 2015.

Performance-based Restricted Stock Units RSUs have a one-year measurement period, and their vesting is contingent on our achievement of a Corporate EBITDA goal during that period. The EBITDA threshold is set at a level to ensure adequate cash flow to fund dividends and capital expenditure commitments. If the threshold goal is met, one-fourth of the RSUs vest immediately, and the remaining three-fourths are subject to annual time-based vesting over the remaining three years of the vesting period. The RSUs convert to an equal number of shares of restricted stock during this time-vesting period, except for Mr. Somerhalder, whose awards remain restricted stock units during the entire vesting period. Dividends declared on our common stock while an award remains outstanding will be credited to the award in the form of additional shares having a value equal to the dividend amount and being subject to the same vesting requirements. The RSU awards are designed to focus the executives on our EBITDA and to provide retention value during the vesting period.

For 2015, because our EBITDA exceeded the threshold for the RSUs, one-fourth of the awards will vest on March 1, 2016, and the remaining units will convert to restricted stock with annual time-based vesting through 2019, except for Mr. Somerhalder's award. By the terms of Mr. Somerhalder's 2015 and 2014 awards, the Board determined that a successful chief executive officer transition was in place, and therefore upon his retirement on December 31, 2015, his RSUs became vested and non-forfeitable, and the shares subject to such awards will be issued to him during their normal vesting period. The value of the 2015 RSU awards as of the date of grant is reflected in the 2015 Grants of Plan-Based Awards Table and in the Stock Awards column of the Summary Compensation Table.

Performance Threshold (Corporate EBITDA)	Actual Result (Corporate EBITDA Achieved)
$911 million	$1.16 billion

Performance Share Units PSUs granted in 2015 vest over a three-year period with performance measures based upon RTSR, which is weighted at 75%, and Cumulative Core EPS, which is weighted at 25%.

RTSR is measured by ranking our relative stock price and dividend performance to the companies in the executive compensation peer group described under the caption "How we Make Compensation Decisions." The use of RTSR as a performance measure requires executive focus that is aligned with the interests of shareholders and provides diversity in our use of performance indicators.

For the purposes of determining PSUs, Total Shareholder Return is defined as:
$Price_{begin}$ = share price at the beginning of the period, based on a 20-day average
$Price_{end}$ = share price at the end of the period, based on a 20-day average
Dividends = total dividends per share paid for the period
TSR = ($Price_{end}$ - $Price_{begin}$ + Dividends)/$Price_{begin}$

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Once the actual performance is computed, PSUs earned with respect to the RTSR component may increase or decrease from target grant levels, depending upon our performance relative to our executive compensation peer group, according to the following scale:

TSR Rank	Percentile Rank	Shares Earned as % of Target Shares (75% Weighting)	
1	100%	200%	Maximum
2	92%	184%	
3	83%	166%	
4	75%	150%	
5	67%	134%	
6	58%	116%	
7	50%	100%	Target
8	42%	84%	
9	33%	66%	
10	25%	50%	Threshold
>10	0%	0%	

At the time performance goals were established, the Compensation Committee provided that Cumulative Core EPS would be calculated as our EPS, excluding wholesale services and the same items excluded from the calculation of 2015 Plan EPS described under the caption "How We Tie Pay to Performance." The Cumulative Core EPS component included the following goals, with results interpolated on a straight line basis between the following performance levels:

Performance	Cumulative Core EPS Performance	Shares Earned as % of Target Shares (25% Weighting)
Threshold (2% CAGR)	$7.84	50%
Target (5.7% CAGR)	$8.30	100%
Maximum (8% CAGR)	$8.80	200%

After determining performance for the RTSR component and the Cumulative Core EPS component, the resulting awards will be settled half in cash and half in shares. To promote officer share ownership, the cash portion must first be used to cover the taxes incurred on the total award.

By the terms of Mr. Somerhalder’s 2015 and 2014 awards, the Board determined that a successful chief executive officer transition was in place, and therefore upon his retirement on December 31, 2015, the service condition for those awards was satisfied. Mr. Somerhalder’s 2015 and 2014 awards will continue to vest based on our performance over the applicable performance period.

PSUs are not credited with dividend equivalents. When determining the number of PSUs to be granted, however, the Compensation Committee factors in the value of dividends expected to be paid during the vesting period.

During the most recently completed three-year performance period (January 1, 2013 to December 31, 2015), we achieved an RTSR percentile rank of 72.7%, which exceeded the threshold target level and resulted in 145% of the target PSUs earned. Accordingly, the PSUs granted in 2013 (having a 2013-2015 performance period and based solely on RTSR goals) paid out in the following amounts:

Payout of 2013 PSUs (2013-2015 Performance Period)

Name	Number of Shares	Cash Payout
John W. Somerhalder II	40,847	$2,636,201
Andrew W. Evans	10,150	655,081
Elizabeth W. Reese	2,212	142,698
Henry P. Linginfelter	9,926	640,560
Paul R. Shlanta	6,286	405,698
Peter I. Tumminello	3,205	206,786

Continuity Agreements

Each of our executives has a change-in-control severance agreement, referred to as a continuity agreement. The Compensation Committee believes these agreements are desirable because of the retentive value they provide during critical periods relating to potential change in control. Each of the agreements has a term that originally was scheduled to run through December 31, 2015, but was automatically extended upon the August 24, 2015 announcement of the proposed merger with Southern Company. Accordingly, these agreements will remain in place until the second anniversary of the closing of the proposed merger with Southern Company unless the merger is abandoned. These agreements do not contain an excise tax gross-up and provide that no severance payments or benefits may be paid under the agreements unless a change in control is actually consummated and the executive has a qualifying termination of employment. The Board has determined that Mr. Somerhalder's retirement on December 31, 2015 will be treated as a qualifying termination for purposes of his continuity agreement. Accordingly, if the merger with Southern Company is completed, Mr. Somerhalder will be entitled to receive certain severance benefits.

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Tables disclosing the estimated costs associated with these agreements, and footnotes describing their principal terms, are presented under the caption “Potential Payments upon Termination or Change in Control.”
Other Policies Governing our Executive Compensation Program
Grants of Long-Term Incentive Awards Pursuant to our Policy on Granting Equity Compensation Awards, annual equity awards typically are granted on the third trading day following our release of year-end financial results. Such awards are approved not more than 30 days in advance by the Compensation Committee or the Board. The number of shares subject to each such equity award is determined based on the dollar value for the awards approved by the Compensation Committee or the Board and the fair market value of our common stock on the grant date. The policy prohibits the Compensation Committee, the Board, and any member of our management from backdating or manipulating any equity award, or manipulating the timing of the public release of material information or of any equity award with the intent of benefitting a recipient of the award.
Recoupment Policy We maintain a compensation recoupment policy that became effective January 1, 2012. This policy provides that in the event that we are required to prepare an accounting restatement due to material noncompliance with financial reporting requirements under the U.S. securities laws, it will seek to recover from any current or former executive officer incentive-based compensation (including equity compensation) received during the three-year period preceding the date on which the accounting restatement was required to be made. The amount to be recovered is the excess of the amount paid calculated by reference to the erroneous data, over the amount that would have been paid to the executive officer calculated using the corrected accounting statement data. This compensation recovery would be applied regardless of whether the executive officer engaged in misconduct or otherwise caused or contributed to the requirement for the restatement.
Hedging and Pledging Policies Our policy prohibits directors and executive officers from engaging in hedging activities involving our stock, holding our stock in a margin account or otherwise pledging our stock as collateral for a loan.
Accounting and Tax Treatment of Direct Compensation Under current accounting principles, we do not expect accounting treatment of differing forms of awards to vary significantly. Accordingly, although accounting treatment is a consideration, we do not expect it to have a material effect on our selection of forms of compensation.
Section 162(m) of the Code places a limit of $1 million on the amount of compensation that we may deduct in any one year with respect to any one of our named executive officers, other than the chief financial officer. However, qualifying performance-based compensation will not be subject to the deduction limit if certain requirements are met. The OPIP is designed to allow the Compensation Committee to grant equity awards that may qualify for the performance-based compensation exemption from Section 162(m), such as RSU's and performance cash awards. The annual incentive program, as a subplan of the OPIP, also allows annual cash incentive awards that may qualify as performance-based compensation.
The Compensation Committee generally expects that awards under our long-term incentive programs and the annual incentive for executives will qualify as performance-based compensation under Section 162(m), but such tax treatment is not guaranteed. In addition, to maintain flexibility in compensating our executives, the Compensation Committee reserves the right to use its judgment to adjust performance goals or to authorize compensation payments that may cause the awards to be subject to the Section 162(m) limit when the Compensation Committee believes that such adjustments or payments are appropriate.
Stock Ownership We maintain stock ownership guidelines designed to ensure sustained, meaningful executive share ownership, align executive long-term interests with shareholders, and demonstrate the commitment of our officers to enhancing long-term shareholder value. Each of our executive officers is encouraged to own shares of our common stock having a market value equal to or exceeding a given multiple of his or her annual base salary-five times for our chief executive officer and three times for each of the other named executive officers. The guidelines require that each executive retain at least 75% of net shares (after tax withholding) from their equity awards until the ownership requirements are met. In calculating compliance with the ownership guidelines, we include all of the stock owned by an executive, restricted stock and in-the-money value of vested stock options, and stock included in an executive’s account under our Retirement Savings Plus Plan and Nonqualified Savings Plan. As of December 31, 2015, each of our named executive officers, with the exception of Ms. Reese, met the ownership guidelines. Ms. Reese met

ownership guidelines under her former position as president of Nicor Gas and continues to make steady progress towards her current ownership guideline of three times annual base salary.

2016 Compensation Program

The Compensation Committee and the Board approved several changes to the compensation program for 2016:

- Effective January 1, 2016, Mr. Evans received a base pay increase to $800,000, in recognition of his new position as president and chief executive officer.
- Effective February 22, 2016, base salaries will be increased by 3% for each of the remaining named executive officers.
- The PSUs granted in 2016 will have one metric: Cumulative Core EPS, which will be measured over a three-year performance period.

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Merger-Related Compensation

For a discussion of the compensation that is or may become payable to our named executive officers or directors that is based on or otherwise relates to the proposed merger with Southern Company, please see the section entitled "Interests of the Company's Directors and Executive Officers in the Merger" in our definitive proxy statement for the special meeting of shareholders that was held on November 19, 2015, which was filed with the SEC on October 13, 2015.

EXECUTIVE COMPENSATION

Compensation Paid to Named Executive Officers

The Summary Compensation Table below reflects the total compensation earned by our former chief executive officer, our chief executive officer, our chief financial officer and each of our three most highly compensated executive officers who served as an executive officer as of December 31, 2015. These six officers are our "named executive officers."

Summary Compensation Table

Name and Principal Position	Year	Salary (1)	Bonus	Stock Awards (3)	Option Awards	Non-Equity Incentive Plan Compensation(4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings (5)	All Other Compensation (6)	Total
John W. Somerhalder II	2015	$1,037,215	$—	$4,593,217	$—	$ 2,024,521	$1,519,154	$136,515	$9,310,622
Former Chairman	2014	969,506	—	4,372,269	—	1,352,563	970,956	159,041	7,824,335
and Chief Executive Officer	2013	931,725	—	3,671,374	—	1,921,067	—	64,050	6,588,216
Andrew W. Evans	2015	675,136	—	1,962,397	—	895,370	38,664	67,283	3,638,850
President and Chief	2014	553,349	—	1,286,041	—	462,102	351,600	75,687	2,728,779
Executive Officer	2013	517,524	—	912,260	—	632,932	—	40,482	2,103,198
Elizabeth W. Reese Executive Vice President and Chief Financial Officer	2015	410,903	—	697,896	—	420,659	23,922	108,037	1,661,417
Henry P. Linginfelter	2015	582,229	—	1,149,475	—	671,721	47,834	70,994	2,522,253
Executive Vice	2014	541,329	—	1,094,114	—	594,383	449,150	71,654	2,750,630
President, Distribution Operations	2013	508,211	—	892,180	—	617,334	—	39,356	2,057,081
Paul R. Shlanta	2015	477,819	—	707,577	—	466,323	50,055	65,491	1,767,265
Executive Vice	2014	446,627	—	673,292	—	435,470	363,058	64,234	1,982,681
President, General Counsel and Chief Ethics and Compliance Officer	2013	424,917	—	565,129	—	442,494	—	39,475	1,472,015
Peter I. Tumminello	2015	423,631	—	692,317	—	2,094,870	271,968	143,554	3,626,340
Executive Vice	2014	363,961	—	343,157	—	3,550,000	297,880	58,092	4,613,090
President, Nonregulated Businesses	2013	349,777	200,000 (2)	488,412	—	798,076	—	45,560	1,881,825

(1) For each of the named executive officers, includes earnings that were eligible for deferral, at the election of the named executive officer, under our Retirement Savings Plus Plan and Nonqualified Savings Plan.

(2) Reflects the cash portion of a special award granted to Mr. Tumminello in connection with the sale of Compass Energy in 2013.

(3) Reflects the aggregate grant date fair value of stock awards, which was computed in accordance with FASB ASC Topic 718 without regard to estimated forfeitures related to service-based vesting conditions. The assumptions used in calculating these amounts are discussed in Note 8 to our consolidated financial statements under Item 8 herein. The grant date fair value of the restricted stock units granted in 2015 was determined by reference to the closing price of the shares on the grant date. The grant date fair value of the performance unit awards granted in 2015 was computed by multiplying (i) the target number of units awarded to each named executive officer, which was the assumed probable outcome as of the grant date, by (ii) the closing price of the underlying shares on the grant date. Assuming, instead, that the highest level of performance conditions would be achieved, the grant date fair values of these performance unit awards would have been $7,099,501 for Mr. Somerhalder, $3,030,975 for Mr. Evans, $1,077,113 for Ms. Reese, $1,776,470 for Mr. Linginfelter, $1,093,703 for Mr. Shlanta and $1,069,456 for Mr. Tumminello.

(4) Reflects annual incentive compensation earned under our annual incentive plan (or Mr. Tumminello's annual incentive arrangement).

(5) Reflects the aggregate change in the actuarial present value of the named executive officer's accumulated benefit under the Retirement Plan, which we refer to as the Pension Plan, and the Excess Plan, both of which are defined benefit plans, and, in addition, for Mr. Somerhalder, under the terms set forth in an individual agreement. None of the named executive officers received any interest on deferred compensation at an above-market rate of interest.

(6) The following table reflects the items that are included in the "All Other Compensation" column for 2015.

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All Other Compensation Detail

Name	Our Contributions to the Retirement Savings Plus Plan (1)	Our Contributions to the Nonqualified Savings Plan (1)	Perquisites (2)	Other Income (3)	Total All Other Compensation
John W. Somerhalder II	$13,780	$108,735	$14,000	$—	$136,515
Andrew W. Evans	11,700	41,583	14,000	—	67,283
Elizabeth W. Reese	11,700	22,055	14,000	60,282	108,037
Henry P. Linginfelter	13,780	47,404	9,810	—	70,994
Paul R. Shlanta	13,780	33,711	18,000	—	65,491
Peter I. Tumminello	13,780	115,774	14,000	—	143,554

(1) Amounts of matching contributions contributed by us to the Retirement Savings Plus Plan and Nonqualified Savings Plan are calculated on the same basis for all plan participants in the relevant plan, including the named executive officers.

(2) Reflects our incurred cost in connection with tax return preparation, financial and estate planning benefits.

(3) In conjunction with her appointment to executive vice president and chief financial officer, Ms. Reese received relocation benefits that were consistent with our relocation policy.

Grants of Plan-Based Awards

The following table presents information concerning plan-based awards granted to each of the named executive officers during 2015.

2015 Grants of Plan-Based Awards

Name	Grant Date	Approval Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)(2) Threshold	Target	Maximum	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold	Target	Maximum	Grant Date Fair Value of Stock and Option Awards (5)
John W. Somerhalder II	02/11/15	02/11/15	$—	$1,104,638	$2,209,275	—	—	—	$—
	02/17/15 (3)	02/11/15	—	—	—	27,815	55,630	111,260	3,549,750
	02/17/15 (4)	02/11/15	—	—	—	—	20,970	—	1,043,467
Andrew W. Evans	02/11/15	02/11/15	—	497,501	995,002	—	—	—	—
	02/17/15 (3)	02/11/15	—	—	—	8,180	16,360	32,720	1,043,932
	02/17/15 (4)	02/11/15	—	—	—	—	6,170	—	307,019
	05/28/15 (3)	05/28/15	—	—	—	3,695	7,390	14,780	471,556
	05/28/15 (4)	05/28/15	—	—	—	—	2,780	—	139,890
Elizabeth W. Reese	02/11/15	02/11/15	—	240,176	480,352	—	—	—	—
	02/17/15 (3)	02/11/15	—	—	—	1,610	3,220	6,440	205,468
	02/17/15 (4)	02/11/15	—	—	—	—	1,210	—	60,210
	05/28/15 (3)	05/28/15	—	—	—	2,610	5,220	10,440	333,088
	05/28/15 (4)	05/28/15	—	—	—	—	1,970	—	99,130

Henry P. Linginfelter	02/11/15	02/11/15	—	366,408	732,817	—	—	—	—
	02/17/15 (3)	02/11/15	—	—	—	6,960	13,920	27,840	888,235
	02/17/15 (4)	02/11/15	—	—	—	—	5,250	—	261,240
Paul R. Shlanta	02/11/15	02/11/15	—	254,440	508,879	—	—	—	—
	02/17/15 (3)	02/11/15	—	—	—	4,285	8,570	17,140	546,852
	02/17/15 (4)	02/11/15	—	—	—	—	3,230	—	160,725
Peter I. Tumminello	02/11/15	02/11/15	—	537,500	662,500	—	—	—	—
	02/17/15 (3)	02/11/15	—	—	—	2,180	4,360	8,720	278,212
	02/17/15 (4)	02/11/15	—	—	—	—	1,640	—	81,606
	05/28/15 (3)	05/28/15	—	—	—	2,010	4,020	8,040	256,516
	05/28/15 (4)	05/28/15	—	—	—	—	1,510	—	75,983

(1) Reflects annual incentive opportunity for 2015 under the annual incentive plan and the OPIP.

(2) The annual incentive award includes a corporate component and a business performance component. The threshold payout amount for the 2015 corporate component was as follows: $331,391 for Mr. Somerhalder; $149,250 for Mr. Evans; $69,525 for Ms. Reese; $109,922 for Mr. Linginfelter; and $76,332 for Mr. Shlanta. The 2015 business performance component consisted of a series of differently-weighted metrics and could pay out anywhere from 0% to 200% of target. Accordingly, the business performance component did not include a threshold amount. The annual incentive award for Mr. Tumminello is not subject to a true maximum as it is based on an incentive pool. For additional detail, refer to the caption "Annual Incentive Award for Mr. Tumminello" herein.

(3) Reflects performance share units granted under the OPIP with a three-year performance measurement period that ends December 31, 2017. These units are payable 50% in shares of our common stock and 50% in cash.

(4) Reflects restricted stock units granted under the OPIP with a 12-month performance measurement period that ended December 31, 2015.

(5) Reflects the aggregate grant date fair value of stock awards, which are based on target-level award and computed in accordance with FASB ASC Topic 718. The assumptions used in calculating these amounts are discussed in Note 8 of our consolidated financial statements under Item 8 herein.

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Outstanding Equity Awards at Fiscal Year End

The following table presents information concerning outstanding equity awards held by the named executive officers as of December 31, 2015.

Outstanding Equity Awards at 2015 Fiscal Year End

Name		Date of Grant	Option Awards: Number of Securities Underlying Unexercised Options Exercisable	Number of Securities Underlying Unexercised Options Unexercisable	Option Exercise Price	Option Expiration Date	Stock Awards: Number of Shares or Units of Stock that Have Not Vested	Market Value of Shares or Units of Stock that Have Not Vested	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights that Have Not Vested
John W. Somerhalder II	(1)	02/05/13	—	—	$ —	—	16,100	$ 1,027,341	—	$ —
	(2)	02/05/13	—	—	—	—	56,340	3,595,055	—	—
	(5)	02/10/14	—	—	—	—	—	—	17,115	1,092,108
	(8)	02/10/14	—	—	—	—	—	—	61,020	3,893,686
	(9)	02/17/15	—	—	—	—	—	—	20,970	1,338,096
	(12)	02/17/15	—	—	—	—	—	—	55,630	3,549,750
Andrew W. Evans	(1)	02/04/13	—	—	—	—	4,000	255,240	—	—
	(2)	02/04/13	—	—	—	—	14,000	893,340	—	—
	(6)	02/10/14	—	—	—	—	5,033	321,156	—	—
	(8)	02/10/14	—	—	—	—	—	—	17,950	1,145,390
	(10)	02/17/15	—	—	—	—	6,170	393,708	—	—
	(12)	02/17/15	—	—	—	—	—	—	16,360	1,043,932
	(13)	05/28/15	—	—	—	—	2,780	177,392	—	—
	(14)	05/28/15	—	—	—	—	—	—	7,390	471,556
Elizabeth W. Reese	(2)	02/04/13	—	—	—	—	3,050	194,621	—	—
	(3)	02/04/13	—	—	—	—	873	55,706	—	—
	(7)	02/10/14	—	—	—	—	900	57,429	—	—
	(8)	02/10/14	—	—	—	—	—	—	3,210	204,830
	(11)	02/17/15	—	—	—	—	1,210	77,210	—	—
	(12)	02/17/15	—	—	—	—	—	—	3,220	205,468
	(13)	05/28/15	—	—	—	—	1,970	125,706	—	—
	(14)	05/28/15	—	—	—	—	—	—	5,220	333,088
Henry P. Linginfelter	(1)	02/04/13	—	—	—	—	3,913	249,689	—	—
	(2)	02/04/13	—	—	—	—	13,690	873,559	—	—
	(6)	02/10/14	—	—	—	—	4,283	273,298	—	—
	(8)	02/10/14	—	—	—	—	—	—	15,270	974,379
	(10)	02/17/15	—	—	—	—	5,250	335,003	—	—
	(12)	02/17/15	—	—	—	—	—	—	13,920	888,235

Paul R. Shlanta	(1)	02/04/13	—	—	—	—	2,480	158,249	—	—
	(2)	02/04/13	—	—	—	—	8,670	553,233	—	—
	(6)	02/10/14	—	—	—	—	2,633	168,012	—	—
	(8)	02/10/14	—	—	—	—	—	—	9,400	599,814
	(10)	02/17/15	—	—	—	—	3,230	206,106	—	—
	(12)	02/17/15	—	—	—	—	—	—	8,570	546,852
Peter I. Tumminello	(1)	02/04/13	—	—	—	—	1,260	80,401	—	—
	(2)	02/04/13	—	—	—	—	4,420	282,040	—	—
	(4)	05/03/13	—	—	—	—	1,523	97,183	—	—
	(6)	02/10/14	—	—	—	—	1,343	85,697	—	—
	(8)	02/10/14	—	—	—	—	—	—	4,790	305,650
	(10)	02/17/15	—	—	—	—	1,640	104,648	—	—
	(12)	02/17/15	—	—	—	—	—	—	4,360	278,212
	(13)	05/28/15	—	—	—	—	1,510	96,353	—	—
	(14)	05/28/15	—	—	—	—	—	—	4,020	256,516

(1) Restricted stock units having satisfied the criteria for the applicable performance measurement period, converted into an equal number of shares of restricted stock and vesting at the rate of one-third per year, with vesting dates on March 1, 2015, March 1, 2016 and March 1, 2017.

(2) Performance share unit awards having a performance measurement period related to our RTSR, with the measurement period ended December 31, 2015. Awards shall be payable 50% in shares of our common stock and 50% in cash.

(3) A four-year restricted stock award with a three-year ratable vesting requirement with vesting dates of March 1, 2015, March 1, 2016 and March 1, 2017.

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(4) A restricted stock award with a three-year ratable vesting requirement with vesting dates of May 3, 2014, May 3, 2015 and May 3, 2016.

(5) Restricted stock units having satisfied the criteria for the applicable performance measurement period that remain restricted stock units until the vesting dates and then converting into an equal number of shares of restricted stock and vesting at the rate of one-fourth per year, with vesting dates on March 1, 2015, March 1, 2016, March 1, 2017 and March 1, 2018.

(6) Restricted stock units having satisfied the criteria for the applicable performance measurement period, converted into an equal number of shares of restricted stock and vesting at the rate of one-fourth per year, with vesting dates on March 1, 2015, March 1, 2016, March 1, 2017 and March 1, 2018.

(7) A restricted stock award with a four-year ratable vesting requirement with vesting dates on March 1, 2015, March 1, 2016, March 1, 2017 and March 1, 2018.

(8) Performance share unit awards having a performance measurement period related to our RTSR, with the measurement period ending on December 31, 2016. Awards shall be payable 50% in shares of our common stock and 50% in cash.

(9) Restricted stock units having satisfied the criteria for the applicable performance measurement period that remain restricted stock units until the vesting dates and then converting into an equal number of shares of restricted stock and vesting at the rate of one-fourth per year, with vesting dates on March 1, 2016, March 1, 2017, March 1, 2018 and March 1, 2019.

(10) Restricted stock units having satisfied the criteria for the applicable performance measurement period, and then converting into an equal number of shares of restricted stock and vesting at the rate of one-fourth per year, with vesting dates on March 1, 2016, March 1, 2017, March 1, 2018 and March 1, 2019.

(11) A restricted stock award with a four-year ratable vesting requirement with vesting dates of March 1, 2016, March 1, 2017, March 1, 2018 and March 1, 2019.

(12) Performance share unit awards having a performance measurement period related to our RTSR and Cumulative Core EPS, with the measurement period ending on December 31, 2017. Awards shall be payable 50% in shares of our common stock and 50% in cash.

(13) Restricted stock units having satisfied the criteria for the applicable performance measurement period, and then converting into an equal number of shares of restricted stock and vesting at the rate of one-fourth per year, with vesting dates on March 1, 2016, March 1, 2017, March 1, 2018 and March 1, 2019.

(14) Performance share unit awards have a performance measurement period related to our RTSR and Cumulative Core EPS, with the measurement period ending on December 31, 2017. Awards shall be payable 50% in shares of our common stock and 50% in cash.

Option Exercises and Stock Vested

The following table presents information concerning stock options exercised by our named executive officers in 2015 and stock awards held by our named executive officers that vested in 2015.

2015 Stock Option Exercises and Stock Vested

Name	Option Awards		Stock Awards	
	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting [1]	Value Realized on Vesting [1]
John W. Somerhalder II	384,400	$9,820,071	42,383	$2,206,359
Andrew W. Evans	—	—	25,995	1,285,836
Elizabeth W. Reese	—	—	2,745	147,383
Henry P. Linginfelter	—	—	25,533	1,262,452
Paul R. Shlanta	20,540	532,744	6,593	343,019
Peter I. Tumminello	12,870	348,508	19,851	965,060

(1) Represents the number of shares that vested in 2015 and the aggregate value of such shares based upon the fair market value of our common stock on the applicable vesting date.

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Pension Benefits

The table below shows the present value of accumulated benefits payable to each of the named executive officers, including the number of years of service credited to each such named executive officer under our Pension Plan and Excess Plan, and, for Mr. Somerhalder, under terms set forth in an individual agreement. Assumptions used in the calculations are set forth in a table below the footnotes to the following table. The plan terms described in the footnotes to the following table apply to a broad-based category of employees, which includes each of the named executive officers.

2015 Pension Benefits

Name	Plan Name (1)(2)	Number of Years Credited Service	Present Value of Accumulated Benefit	Payments During Last Fiscal Year
John W. Somerhalder II	Pension Plan	10	$325,903	$—
	Excess Plan	10	2,208,630	—
	Individual Agreement (3)	10(4)	2,140,242	—
Andrew W. Evans	Pension Plan	14	343,710	—
	Excess Plan	14	701,560	—
Elizabeth W. Reese	Pension Plan	15	353,918	—
	Excess Plan	15	145,533	—
Henry P. Linginfelter	Pension Plan	35	758,324	—
	Excess Plan	35	816,848	—
Paul R. Shlanta	Pension Plan	18	550,201	—
	Excess Plan	18	828,124	—
Peter I. Tumminello	Pension Plan	12	309,261	—
	Excess Plan	12	874,060	—

(1) The AGL Resources Inc. Retirement Plan, which we refer to as the Pension Plan, is a broad-based, tax-qualified defined benefit plan. Generally, union employees who have a hire date on, or before, December 31, 2012, and non-union employees who have a hire date on, or before, December 31, 2011, are eligible to participate in the Pension Plan, upon completion of one year of service and attainment of age 21. Pension Plan benefits are determined, generally, by a “career average” earnings formula. Generally, the Pension Plan provides that the term “compensation” means base pay, overtime and bonuses. Benefits vest upon completion of five years of service. A participant’s accrued benefit is calculated based upon the normal form of benefits for that participant, as of the date the participant will reach the Pension Plan’s normal retirement age of 65. The normal form of benefits for a participant who is single is a life annuity. The normal form for a married participant is a joint and 50% survivor annuity. The Pension Plan provides for the payment of benefits in other forms, if the participant so elects. These other forms include various annuities, and (for a broad class of employees, including the named executive officers) only in cases where a participant’s benefit is less than $10,000, a single lump sum payment. Other employee groups may elect an unlimited lump sum. A participant may elect to receive benefits earlier than normal retirement age, once the participant has reached the early retirement age of 55. If a participant elects to commence benefits earlier than normal retirement age, the monthly payments will be reduced to reflect the fact that payments may continue over a longer period of time than if the employee had retired at normal retirement age. If the participant satisfies the Pension Plan’s requirements for early retirement (age 55 with 5 years of service), the reduced amount is subsidized so that the reduction from the full normal retirement benefit is less severe than a full actuarial reduction. If the participant does not satisfy the early retirement criteria, the reduced payments represent the actuarial equivalent of the full normal retirement benefit.

(2) The AGL Resources Inc. Excess Benefit Plan, which we refer to as the Excess Plan, is a non-qualified, and unfunded, defined benefit plan designed for the benefit of a select group of management or highly compensated employees. Specifically, the Excess Plan is available to certain of our employees who have a hire date on, or before, December 31, 2011, who are adversely affected by limitations set forth in the U.S. tax code, imposed on

benefits under a tax-qualified plan, such as the Pension Plan. Benefits under the Excess Plan are calculated pursuant to a formula that first determines what the participant's benefit would be under the Pension Plan, but for the imposition of the U.S. tax code limits and then subtracts from that figure, the amount the participant will actually be entitled to under the Pension Plan. Benefits under the Excess Plan are paid in the same forms available under the Pension Plan, and are distributed at the later of separation from service or age 62.

(3) Mr. Somerhalder's individual agreement provides for one additional year of benefit accrual credit under the Pension Plan and Excess Plan for each year of service completed, up to a maximum of five additional years, using the eligible compensation for the year prior to the separation of service.

(4) In accordance with the terms of Mr. Somerhalder's individual agreement, a maximum of five years of credited service is used in this calculation.

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Pension Benefit Assumptions

We used the following assumptions in calculating the present value of accumulated benefits:

Retirement age	Earliest unreduced
Payment form	Life annuity
Discount rate	4.61% at December 31, 2015
Postretirement mortality	RP-2014 mortality table, backed up to 2007 by Scale MP2014 and projected forward with the Mercer SSA intermediate alternative mortality improvement scale
Salary scale	None
Preretirement decrements: (mortality, withdrawals, disability)	None

Nonqualified Deferred Compensation

The table below relates to and describes compensation deferred by named executive officers under our Nonqualified Savings Plan.

Nonqualified Deferred Compensation

Name	Executive Contributions in Last FY (1)	Registrant Contributions in Last FY (2)	Aggregate Earnings in Last FY	Aggregate Withdrawals/ Distributions	Aggregate Balance at Last FYE (3)
John W. Somerhalder II	$167,285	$108,735	$602,924	$—	$3,523,639
Andrew W. Evans	63,974	41,582	(226)	—	1,194,907
Elizabeth W. Reese	45,439	22,055	133,666	—	811,869
Henry P. Linginfelter	76,905	47,404	3,003	—	1,058,890
Paul R. Shlanta	53,950	33,711	(5,894)	—	1,408,828
Peter I. Tumminello	222,421	115,774	(53,441)	—	1,890,195

(1) All amounts set forth in this column are included in the Summary Compensation Table as a component of the Salary column.

(2) All amounts set forth in this column represent our contributions to our Nonqualified Savings Plan and are included in the Summary Compensation Table as a component of the All Other Compensation column.

(3) Amounts set forth in this column for each named executive officer include amounts previously reported in the Summary Compensation Table, in the previous years when earned if that officer's compensation was required to be disclosed in a previous year. Amounts previously reported in such years include previously earned, but deferred, salary and annual incentive and our matching contributions. This total reflects each named executive officer's deferrals, matching contributions and investment experience.

The Nonqualified Savings Plan allows eligible employees to defer up to 75% of base salary and up to 100% of annual incentive pay as before-tax contributions. The timing restrictions for contribution deferral elections are intended to comply with Section 409A of the U.S. tax code, as well as other applicable tax code provisions. For certain employees who participate in our Pension Plan, including the named executive officers, we match contributions at a rate of 65% of participant contributions, up to the first 8% of the participant's covered compensation. However, matching contributions under the Nonqualified Savings Plan are offset by the maximum matching contributions the participant could receive under our tax-qualified Retirement Savings Plus Plan. Each participant in the Nonqualified Savings Plan has a plan account, which represents a bookkeeping entry reflecting contributions and earnings/losses on the actual performance of the participant's notional investments. Participants are always 100% vested in their own contributions and vest in employer matching contributions over a three-year period according to a vesting schedule. The vesting associated with employer matching contributions is based upon employment service with us and is not subject to vesting based upon when the contribution itself was made. Distributions of a participant's account balance occur following a termination of employment. Participants have the option of taking distributions, following termination of employment, in the following forms: (i) a single lump sum cash payment; (ii) a lump sum cash payment of a portion of the participant's account, with the remainder distributed in up to ten equal annual installments; or (iii) between two and ten annual installments. The notional investment choices under the Nonqualified Savings Plan are similar to the investment choices in the Retirement Savings Plus Plan.

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Potential Payments upon Termination or Change in Control

We have entered into certain agreements and maintain certain plans that will require us to provide compensation and benefits to our named executive officers in the event of a termination of employment following a change in control. We do not otherwise maintain any agreement, plan or practice that specifically provides for compensation to a named executive officer upon termination of employment. The appropriate amount of compensation payable to each named executive officer in each relevant situation, in each case assuming a termination of employment and/or a change in control on December 31, 2015, is listed in the tables below. Footnotes relating to all of these tables follow the last table.

As noted above, Mr. Somerhalder retired as our chairman and chief executive officer on December 31, 2015. The amounts he is entitled to receive in connection with his retirement are described in the Voluntary Termination column below, and the related footnotes to the following table. The following table also describes the potential payments Mr. Somerhalder would have received in connection with other terminations of employment. As noted above, the Board determined that Mr. Somerhalder's retirement will be treated as a qualifying termination for purposes of his continuity agreement. The amounts he would have been entitled to receive if a change in control had occurred on December 31, 2015 are described in the Change in Control column below, and the related footnotes to the following table.

Executive Benefits and Payments Upon Termination (1)	Potential Payments Upon Termination Other Than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Disability (6)	Death (6)
	Voluntary Termination(2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Voluntary, Involuntary or Good Reason Termination (5)		
Cash Severance:						
Base Salary	$—	(3)	$—	$2,008,432	$—	$—
Short-term Incentive	2,024,521	(3)	—	4,206,941	2,024,521	2,024,521
Long-term Incentives:						
Unvested Restricted Stock	—	(3)	—	1,027,341	970,295	970,295
Unvested Restricted Stock Units	2,430,204	(3)	—	2,430,204	1,644,830	2,369,584
Unvested Performance Share Units	12,656,267	(3)	—	12,656,267	8,991,914	11,358,371
Unvested Stock Options	—	—	—	—	—	—
Benefits & Perquisites:						
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	123,218	(6)	(6)
Disability Benefits	—	—	—	—	(6)	(6)
Death Benefit	—	—	—	—	(6)	(6)
Accrued Vacation Pay	19,312	19,312	19,312	19,312	19,312	19,312
Outplacement Assistance	—	(3)	—	—	—	—
Sub-Total:	(2)	(3)	19,312	22,471,715	(6)	(6)
280G Cutback:	N/A	N/A	N/A	(1,129,395)	N/A	N/A
TOTAL:	(2)	(3)	$19,312	$21,342,320	(6)	(6)

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The following table describes the potential payments upon termination of employment for Mr. Evans, our president and chief executive officer.

Executive Benefits and Payments Upon Termination (1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Disability (6)	Death (6)
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)		
Cash Severance:						
Base Salary	$—	(3)	$—	$1,400,000	$—	$—
Short-term Incentive:	—	(3)	—	1,625,393	895,370	895,370
Long-term Incentives:						
Unvested Restricted Stock	—	(3)	—	576,396	388,284	388,284
Unvested Restricted Stock Units	(2)	(3)	—	571,100	247,009	571,100
Unvested Performance Share Units	(2)	(3)	—	2,563,056	2,564,205	3,574,445
Unvested Stock Options	—	—	—	—	—	—
Benefits & Perquisites:						
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	64,116	(6)	(6)
Disability Benefits	—	—	—	—	(6)	(6)
Death Benefit	—	—	—	—	(6)	(6)
Accrued Vacation Pay	15,385	15,385	15,385	15,385	15,385	15,385
Outplacement Assistance	—	(3)	—	175,000	—	—
Sub-Total:	(2)	(3)	15,385	6,990,446	(6)	(6)
280G Cutback:	N/A	N/A	N/A	—	N/A	N/A
TOTAL	(2)	(3)	$15,385	$6,990,446	(6)	(6)

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The following table describes the potential payments upon termination of employment for Ms. Reese, our executive vice president and chief financial officer.

Executive Benefits and Payments Upon Termination [1]	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Disability [6]	Death [6]
	Voluntary Termination [2]	Involuntary Not for Cause Termination [3]	For Cause Termination [4]	Involuntary or Good Reason Termination [5]		
Cash Severance:						
Base Salary	$—	[3]	$—	$880,000	$—	$—
Short-term Incentive:	—	[3]	—	730,069	420,659	420,659
Long-term Incentives:						
Unvested Restricted Stock	—	[3]	—	190,345	129,151	129,151
Unvested Restricted Stock Units	[2]	[3]	—	125,706	47,156	125,706
Unvested Performance Share Units	[2]	[3]	—	598,155	598,346	957,341
Unvested Stock Options	—	—	—	—	—	—
Benefits & Perquisites:						
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	66,504	[6]	[6]
Disability Benefits	—	—	—	—	[6]	[6]
Death Benefit	—	—	—	—	[6]	[6]
Accrued Vacation Pay	7,192	7,192	7,192	7,192	7,192	7,192
Outplacement Assistance	—	[3]	—	110,000	—	—
Sub-Total:	[2]	[3]	7,192	2,707,971	[6]	[6]
280G Cutback:	N/A	N/A	N/A	(312,335)	N/A	N/A
TOTAL	[2]	[3]	$7,192	$2,395,636	[6]	[6]

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The following table describes the potential payments upon termination of employment for Mr. Linginfelter, our executive vice president, distribution operations.

Executive Benefits and Payments Upon Termination (1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Disability (6)	Death (6)
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)		
Cash Severance:						
Base Salary	$—	(3)	$—	$1,127,410	$—	$—
Short-term Incentive	—	(3)	—	1,479,532	671,721	671,721
Long-term Incentives:						
Unvested Restricted Stock	—	(3)	—	522,987	361,165	361,165
Unvested Restricted Stock Units	(2)	(3)	—	335,003	153,591	335,003
Unvested Performance Share Units	(2)	(3)	—	2,211,527	2,212,357	2,804,513
Unvested Stock Options	—	—	—	—	—	—
Benefits & Perquisites:						
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	111,321	(6)	(6)
Disability Benefits	—	—	—	—	(6)	(6)
Death Benefit	—	—	—	—	(6)	(6)
Accrued Vacation Pay	4,607	4,607	4,607	4,607	4,607	4,607
Outplacement Assistance	—	(3)	—	140,926	—	—
Sub-Total:	(2)	(3)	4,607	5,933,313	(6)	(6)
280G Cutback:	N/A	N/A	N/A	—	N/A	N/A
TOTAL	(2)	(3)	$4,607	$5,933,313	(6)	(6)

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The following table describes the potential payments upon termination of employment for Mr. Shlanta, our executive vice president, general counsel and chief ethics and compliance officer.

Executive Benefits and Payments Upon Termination (1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Disability (6)	Death (6)
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)		
Cash Severance:						
Base Salary	$—	(3)	$—	$925,235	$—	$—
Short-term Incentive	466,323	(3)	—	1,051,632	466,323	466,323
Long-term Incentives:						
Unvested Restricted Stock	—	(3)	—	326,261	226,526	226,526
Unvested Restricted Stock Units	44,750	(3)	—	206,106	94,503	206,106
Unvested Performance Share Units	1,312,276	(3)	—	1,383,911	1,384,422	1,748,968
Unvested Stock Options	—	—	—	—	—	—
Benefits & Perquisites:						
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	122,865	(6)	(6)
Disability Benefits	—	—	—	—	(6)	(6)
Death Benefit	—	—	—	—	(6)	(6)
Accrued Vacation Pay	—	—	—	—	—	—
Outplacement Assistance	—	(3)	—	115,654	—	—
Sub-Total:	(2)	(3)	—	4,131,664	(6)	(6)
280G Cutback:	N/A	N/A	N/A	—	N/A	N/A
TOTAL	(2)	(3)	$—	$4,131,664	(6)	(6)

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The following table describes the potential payments upon termination of employment for Mr. Tumminello, executive vice president, nonregulated businesses.

Executive Benefits and Payments Upon Termination (1)	Potential Payments Upon Termination Other than in Connection with a Change in Control			Potential Payments Upon Termination Following a Change in Control	Disability (6)	Death (6)
	Voluntary Termination (2)	Involuntary Not for Cause Termination (3)	For Cause Termination (4)	Involuntary or Good Reason Termination (5)		
Cash Severance:						
Base Salary	$—	(3)	$—	$860,000	$—	$—
Short-term Incentive	—	(3)	—	5,157,089	2,094,870	2,094,870
Long-term Incentives:						
Unvested Restricted Stock	—	(3)	—	263,280	184,092	184,092
Unvested Restricted Stock Units	(2)	(3)	—	201,002	84,165	201,002
Unvested Performance Share Units	(2)	(3)	—	790,734	791,053	1,147,495
Unvested Stock Options	—	—	—	—	—	—
Benefits & Perquisites:						
Post-retirement/Post-termination Health Care and Life Insurance	—	—	—	96,167	(6)	(6)
Disability Benefits	—	—	—	—	(6)	(6)
Death Benefit	—	—	—	—	(6)	(6)
Accrued Vacation Pay	—	—	—	—	—	—
Outplacement Assistance	—	(3)	—	107,500	—	—
Sub-Total:	(2)	(3)	—	7,475,772	(6)	(6)
280G Cutback:	N/A	N/A	N/A	—	N/A	N/A
TOTAL	(2)	(3)	$—	$7,475,772	(6)	(6)

Below is a description of the assumptions that we used in creating the tables above. Unless otherwise noted, the descriptions of the payments below are applicable to all of the above tables relating to potential payments upon termination or change in control.

Notes to Potential Payments upon Termination or Change in Control Tables

(1) For purposes of this analysis, we assumed the executive's compensation as current base salary, target annual incentive opportunity and target long-term incentive opportunity, each as of December 31, 2015. Each column assumes the named executive officer's date of termination is December 31, 2015 and the price per share of our common stock on the date of termination is $63.81.

(2) If the executive leaves voluntarily prior to retirement eligibility, compensation stops as of the termination date. All outstanding and unvested long-term incentive awards would be forfeited. No further benefits would be earned under ERISA-qualified plans. Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination and at least six months following the date of termination, or later if the executive had timely elected. Prorated accrued and unused vacation would be paid. If the executive was retirement-eligible at the time of voluntary termination and elected to retire, in addition to commencing retirement benefits, he or she would be entitled to a prorated annual incentive under the annual incentive plan, conditioned on our satisfaction of applicable performance goals, and prorated vesting of unvested

RSUs and PSUs, conditioned on our satisfaction of applicable performance goals. Only Messrs. Somerhalder and Shlanta were retirement eligible on December 31, 2015. Mr. Somerhalder retired on December 31, 2015, and his retirement has been treated as a Qualifying Retirement for purposes of the RSUs and PSUs awarded to him in 2014 and 2015. Accordingly, Mr. Somerhalder is entitled to receive the full value of such RSUs on the scheduled vesting dates and the value of such PSUs on the scheduled vesting dates conditioned only on our satisfaction of applicable performance goals. The satisfaction of such goals would be measured at the end of the performance period, and any payment would be made at that time. For those who are retirement eligible, the value of the unvested performance-based awards is not currently calculable but has been included based on our share price and actual performance as of December 31, 2015.

(3) If the executive is terminated without cause, a severance agreement may be executed based upon the facts and circumstances of the termination and in exchange for a release of any future liabilities which might otherwise be claimed by the executive. Due to the wide range and variety of circumstances, there is no preset policy governing involuntary severance compensation. However, any terms of such a special agreement would be subject to the review and approval of

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the Compensation Committee. Upon such a termination, no further benefits would be earned under ERISA-qualified plans. Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination and at least six months following the date of termination, or later if the executive had timely elected. Outstanding long-term incentive awards would be forfeited and annual incentive would not be payable. The prorated value of accrued but unused vacation would be paid. If the executive was retirement-eligible at the time of termination, his termination would be treated as a retirement.

(4) If the executive is terminated for cause, compensation stops as of the termination date. All outstanding long-term incentive awards would be forfeited. No further benefits would be earned under ERISA-qualified plans. Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination and at least six months following the date of termination, or later if the executive had timely elected. The prorated value of accrued but unused vacation would be paid.

(5) If within two years of a change in control (as described below) the executive is terminated without cause, or resigns for good reason, the terms and conditions described below under the caption "Payments upon a Termination in connection with a Change in Control" would apply. The Board determined that Mr. Somerhalder's retirement will be treated as a qualifying termination for purposes of his continuity agreement. Accordingly, if a change in control occurs, the terms and conditions described below under "Payments upon a Termination in connection with a Change in Control" also would apply to Mr. Somerhalder.

(6) If the executive's employment terminates as a result of death, a death benefit would be paid to the executive's estate under our death benefit plan in an amount equal to one year's base salary or such multiple of base salary (up to five) as elected and paid for, in part, by the executive. This plan covers all employees and does not discriminate in favor of executives or highly compensated employees. Upon a determination of long-term disability, payments would be made, based on the level of coverage elected and paid for, in part, by the executive, under our group disability plan. Our disability plan is also a plan that does not discriminate in favor of executives, or highly compensated employees. In the event of death or disability, the executive (or the executive's designated beneficiary) also would receive a prorated annual incentive under the annual incentive plan, conditioned on our satisfaction of applicable performance goals. In addition, long-term incentive awards granted prior to 2015 would vest on a pro rata basis with performance conditioned on our satisfaction of applicable performance goals. The satisfaction of such goals would be measured at the end of the performance period, and any payment would be made at that time. Upon a termination due to death, stock options and long-term incentive awards granted in 2015 would vest and become non-forfeitable in full conditioned on our satisfaction of applicable performance goals. The satisfaction of such goals would be measured at the end of the performance period, and any payment would be made at that time. Due to the future performance measurement, the value of the unvested performance-based awards is not currently calculable but has been included based on our share price and actual performance as of December 31, 2015.

Balances related to compensation deferred under the Nonqualified Savings Plan, if any, would be paid out in the year following the year of termination, or later if the executive has so elected. The prorated value of accrued but unused vacation would be paid.

Payments upon a Termination in connection with a Change in Control Each of the named executive officers has a continuity agreement with us, as referenced under the caption "How We Tie Pay to Performance - Continuity Agreements" in the CD&A. The purpose of these agreements is to retain key management personnel and assure continued productivity of such personnel in the event of a change in control.

The continuity agreements define a "change in control" to generally mean the occurrence of any of the following events:

- the acquisition by a person or group of persons of more than 50% of our voting securities, based upon total fair market value or total voting power;
- the acquisition, within a 12-month period by a person or group of more than 35% of the total voting power of our stock;
- the replacement, during a 12-month period of a majority of members of our Board with directors not endorsed by a majority of the incumbent directors; or
- the acquisition by a person or group of persons of our assets which have a fair market value of at least 50% of the fair market value of all of our assets, immediately before such acquisition.

Benefits are provided under the continuity agreements only in the event of a termination without “cause” or resignation for “good reason” within two years after a change in control, or after our announcement of our intention to engage in a transaction that is expected to result in a change in control, provided that a change in control actually occurs. No benefits are provided if a change in control does not occur, for any terminations that occur outside these periods, or for any termination for cause, resignation without good reason, or termination due to death or disability whenever they occur. “Cause” includes failure to perform duties and responsibilities, willful fraud, dishonesty or malfeasance that results in material harm to us, or a plea of guilty or no contest to a felony. “Good reason” includes a material diminution of position, duties or responsibilities; material diminution of base salary or annual incentive opportunity (unless consistent with a diminution for all executives at a comparable level), a material breach by us of any agreement under which the executive provides services, or a material change

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in the geographic location (at least 50 miles) of the executive's primary employment location. The Board determined that Mr. Somerhalder's retirement will be treated as a qualifying termination for purposes of his continuity agreement.
An officer who has a qualifying termination event during the change in control period would be entitled to:

- a severance benefit equal to two times the sum of his or her base salary plus the average annual incentive compensation actually paid during the three years prior to the year of the qualifying termination;
- a prorated annual incentive compensation payment for the year of the qualifying termination, based on the number of days the named executive officer was employed by us during that year and the greater of the target annual incentive for the officer or the incentive that would be paid based upon actual performance through the date of termination;
- two-year continuation of medical, dental and life insurance benefits;
- potential vesting of long-term incentive compensation, pursuant to the terms of the plan the awards were granted under; and
- outplacement assistance.

The executives may also receive reimbursement of legal fees in connection with the enforcement of payments under the continuity agreements.
If the payments under the continuity agreements and under any other compensation arrangement if considered to be contingent upon a change in control, were to equal or exceed three times the base amount permitted under Section 280G(b)(3) of the U.S. tax code, the payments would be reduced and payable only to the maximum amount which could be paid without the imposition of the excise tax under Section 4999 of the U.S. tax code, unless the executive's payment of such excise taxes and all other applicable taxes on the full payment amount would result in him or her receiving a greater resulting amount, net of such taxes. For 2015, calculations performed on amounts potentially payable if severance under the continuity agreements was triggered reflect that a reduction (or "cutback") would be more beneficial to Mr. Somerhalder and Ms. Reese than payment of the extra taxes but not for Messrs. Evans, Linginfelter, Shlanta and Tumminello. Where applicable, the tables reflect the amount of the required cutback and the net payments payable after the cutback was applied.
The continuity agreements contain covenants on the part of the executive relating to the maintenance of our confidential information and that require the executive to refrain from taking action that disparages our reputation or the reputation of any of our subsidiaries or, for a period of 24 months following a qualifying termination, from soliciting our employees or employees of our subsidiaries.

Summary of Potential Payments upon a Change in Control The following table summarizes the value of the payments that each of our named executive officers would receive as a result of the vesting of long-term incentive awards if a change in control had occurred on December 31, 2015, the awards were not assumed or substituted by the successor company, and the executive did not incur a termination of employment. The amounts in the table exclude the value of long-term incentive awards that were vested by their terms on December 31, 2015. If the awards were assumed or substituted by the successor company in such an instance, then the awards will continue to vest pursuant to their original terms and no additional value would be received by our named executive officers.

	John W. Somerhalder II	Andrew W. Evans	Elizabeth W. Reese	Henry P. Linginfelter	Paul R. Shlanta	Peter I. Tumminello
Unvested Restricted Stock	$1,027,341	$576,396	$190,345	$522,987	$326,261	$263,280
Unvested Restricted Stock Units	2,430,204	571,100	125,706	335,003	206,106	201,002
Unvested Performance Share Units	12,656,267	2,563,056	598,155	2,211,527	1,383,911	790,734
Total	$16,113,812	$3,710,552	$914,206	$3,069,517	$1,916,278	$1,255,016

Each column assumes the change in control had occurred on December 31, 2015 and the price per share of our common stock on the date of termination is $63.81. All awards were granted under our OPIP, which provides that such awards will become vested and non-forfeitable immediately following the change in control (absent a qualifying termination of employment) if the surviving entity fails to assume or substitute the awards.

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Equity Compensation Plan Information

The following table provides information as of December 31, 2015, with respect to the shares of our common stock that may be issued under our existing equity compensation plans:

Plan Category	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (1)(a)	Weighted Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column) (1)(a)(c)
Equity compensation plans approved by security holders	440,186	$39.24	2,327,332
Equity compensation plans not approved by security holders	—	—	1,514,116
Total	440,186	—	3,841,448

(1) Includes shares issuable as follows:

Name of Plan	Approved by Security Holders	Active/ Inactive Plan (a)	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Outstanding Options)
Omnibus Performance Incentive Plan, as Amended and Restated	ü	Active	359,586	1,999,876 (b)
Long-Term Incentive Plan (1999)	ü	Inactive	80,600	—
2006 Directors Plan	ü	Active	N/A	11,886
Employee Stock Purchase Plan	ü	Active	N/A	315,570
Subtotal-Approved Plans			440,186	2,327,332
Assumed Nicor Inc. Plan Shares under OPIP (c)	No	Active	—	1,514,116
Subtotal-Not Approved Plans			—	1,514,116
Total			440,186	3,841,448

(a) No further grants will be made under the inactive plan except for reload options that may be granted under outstanding option agreements under the 1999 Long-Term Incentive Plan.

(b) The OPIP includes separate pools of shares for share counting purposes. The amount shown in the table above includes 1 million shares, which are available for future issuance as awards pursuant to stock options or stock appreciation rights under the "Remainder Reserve." If issued pursuant to full value awards (which include awards other than stock options or stock appreciation rights), only 200,000 shares could be issued under the Remainder Reserve. In such event, the number of securities remaining available for future issuance under the OPIP, the subtotal for approved plans, and the total each would decrease by 800,000 shares.

(c) In accordance with the terms of the OPIP, which was approved by our shareholders, shares available under a shareholder-approved plan of a company acquired by us (as appropriately adjusted to reflect the transaction) may be issued under the OPIP pursuant to awards granted to individuals who were not our employees or employees of a related company immediately before such transaction. These assumed shares do not count against the maximum share limitation specified in the OPIP. Such assumption of shares in a merger does not require approval of our shareholders under the rules of the New York Stock Exchange or otherwise. The shares designated as "Assumed Nicor Inc. Plan Shares" in the table above remained available under the Nicor Inc. 2006 Long-Term Incentive Plan, as amended, at the time of our merger with Nicor Inc. These shares were assumed under the OPIP and are available for future issuance to persons who were not our employees or employees of a related company immediately prior to our merger with Nicor Inc.

The Board's Role in Risk Oversight

The Board oversees our risk assessment and risk management processes. It does so in part through the committees of the Board. Our Audit Committee has the responsibility to review with management our (i) policies governing the process by which risk assessment and risk management are undertaken; and (ii) major financial risk exposures and the steps management has taken to monitor and control such exposures. Our Finance and Risk Management Committee has the responsibility to (i) review with management the steps taken by management to ensure compliance with our risk management policies and procedures relating to interest rate risk, currency risk, credit risk, commodity risk and derivatives related to any of the foregoing; (ii) review steps taken by management to establish and monitor trading and risk management systems and controls at our asset management and optimization businesses and to ensure compliance at such businesses with risk management policies and procedures applicable to such businesses; and (iii) review management's assessment of controls and procedures associated with such businesses' management of transactions with affiliates and any reporting obligations to state or federal regulatory authorities. Our chief risk officer provides a quarterly report to the Finance and Risk Management Committee and meets in executive sessions with the Finance and Risk Management Committee at each regularly scheduled meeting. Each of the other committees of the Board has principal responsibility for reviewing and discussing with management those risk exposures: (i) specified in their charters or (ii) identified from time to time by the committees themselves or by the Audit Committee.

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In addition, the Board authorized the formation of our Risk Management Committee (RMC), a committee of certain members of senior management. The RMC is responsible for establishing specific risk management policies and monitoring compliance with, and adherence to, the terms of these policies. Members of the RMC are members of senior management who monitor natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. The RMC 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. We conduct an annual enterprise risk assessment, overseen by a sub-committee of the RMC. The purpose of the assessment includes identifying and rating the management of all of our significant risk exposures. The RMC uses the results of this assessment to prioritize the goals of our risk management program and monitor our major risks. Management reports to the Board any new risks identified since the previous year’s assessment.

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

Directors and Executive Officers The following table presents the number of shares of AGL Resources common stock beneficially owned by each director, each named executive officer and by all executive officers and directors as a group as of December 31, 2015, based on information furnished by them to us. Our named executive officers are those individuals named in the Summary Compensation Table under Item 11, “Executive Compensation.”

Beneficial ownership as reported in the table below has been determined in accordance with SEC regulations and includes shares of common stock which may be acquired within 60 days after December 31, 2015, upon the exercise of outstanding stock options but excludes shares and share equivalents held under deferral plans which are disclosed in a separate column. Unless otherwise indicated, all directors and executive officers have sole voting and investment power with respect to the shares shown. As of December 31, 2015, no individual director or named executive officer beneficially owned 1% or more of our common stock. Our executive officers and directors as a group beneficially owned approximately 1% of our common stock.

Name	Shares of Common Stock Beneficially Owned			
	Owned Shares	Option Shares (1)	Shares and Share Equivalents Held Under Deferral Plans (2)	Total
Sandra N. Bane	3,410	—	17,302	20,712
Thomas D. Bell, Jr.	32,558	—	—	32,558
Norman R. Bobins (3)	12,565	—	—	12,565
Charles R. Crisp	16,739	—	14,589	31,328
Brenda J. Gaines	12,510	—	—	12,510
Arthur E. Johnson	4,338	—	52,113	56,451
Wyck A. Knox, Jr.	14,193	—	48,159	62,352
Dennis M. Love	41,937	—	42,169	84,106
Dean R. O’Hare	22,572	—	931	23,503
Armando J. Olivera	1,875	—	14,466	16,341
John E. Rau (4)	25,080	—	—	25,080
James A. Rubright	22,235	—	26,230	48,465
John W. Somerhalder II (5)	201,174	—	52,759	253,933
Bettina M. Whyte	14,782	—	21,204	35,986
Henry C. Wolf	31,031	—	13,309	44,340
Andrew W. Evans	72,791	—	—	72,791
Elizabeth W. Reese	3,411	—	11,726	15,137
Henry P. Linginfelter	82,150	—	44	82,194
Paul R. Shlanta	54,543	—	—	54,543
Peter I. Tumminello	35,049	—	—	35,049
All executive officers and directors as a group (21 persons) (6)	744,333	—	315,001	1,059,334

(1) Reflects the shares that may be acquired upon exercise of stock options granted under the OPIP, the Long-Term Incentive Plan (1999) (which we refer to as the Long-Term Incentive Plan) and which was the predecessor plan to the OPIP, or under the Officer Incentive Plan.

(2) Represents shares of common stock, common stock equivalents and accrued dividend credits held for non-employee directors under the Amended and Restated Common Stock Equivalent Plan for Non-Employee Directors, which we refer to as the Common Stock Equivalent Plan, and, for the named executive officers, under the Nonqualified Savings Plan. The common stock equivalents track the performance of our common stock and are payable in cash. The shares and share equivalents may not be voted or transferred by the participants.

(3) Includes 502 shares held in a trust for which Mr. Bobins has sole voting and investment power with respect to the shares.

(4) Includes 4,610 shares held in a trust for which Mr. Rau has sole voting and investment power with respect to the shares.

(5) Includes 9,711 shares held in a trust for which Mr. Somerhalder has sole voting and investment power with respect to the shares.

(6) Includes 39,390 shares of a member of the group who is not a named executive officer.

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Owners of More Than 5% of AGL Resources Common Stock We are aware of the following shareholders who beneficially own more than 5% of AGL Resources common stock.

Name and Address of Beneficial Owner	Shares of Common Stock Beneficially Owned	Percent of Class
BlackRock, Inc. 55 East 52nd Street New York, NY 10055	10,333,756 (1)	8.6%
The Vanguard Group, Inc. 100 Vanguard Blvd. Malvern, PA 19355	10,344,726 (2)	8.6%

(1) Based on the Schedule 13G/A filed with the SEC on January 25, 2016, in which BlackRock, Inc. reported that it holds all of its shares as a parent holding company or control person in accordance with Rule 13d-1(b)(1)(ii)(G) of the Exchange Act and has sole voting power with respect to 9,339,720 of its shares and sole dispositive power with respect to all of its shares.

(2) Based on the Schedule 13G/A filed with the SEC on February 10, 2016, in which The Vanguard Group, Inc. (“Vanguard”) reported that it holds all of its shares as an investment advisor in accordance with Rule 13d-1(b)(1)(ii)(E) of the Exchange Act and has sole voting power of 231,808 of the total shares, shared voting power of 11,000 of the total shares, sole dispositive power of 10,109,211 of the total shares and shared dispositive power of 235,515 of the total shares. Based on the Schedule 13G/A, (i) Vanguard Fiduciary Trust Company (“VFTC”), a wholly-owned subsidiary of Vanguard, is the beneficial owner of 186,315 shares or 0.15% of our common stock outstanding as a result of its serving as investment manager of collective trust accounts, and as such, VFTC directs the voting of these 186,315 shares; and (ii) Vanguard Investments Australia, Ltd. (“VIA”), a wholly-owned subsidiary of Vanguard, is the beneficial owner of 94,693 shares or 0.07% of our common stock outstanding as a result of its serving as investment manager of Australian investment offerings, and as such, VIA directs the voting of these 94,693 shares.

Changes in Control

On August 23, 2015, we entered into the Merger Agreement with Southern Company, which, based on the number of common shares and the fair value of debt outstanding as of December 31, 2015, reflects an estimated business enterprise value of AGL Resources of $13.0 billion, including a total equity value of $7.9 billion. When the merger becomes effective, which is expected to occur in the second half of 2016, each share of our common stock, other than certain excluded shares, will convert into the right to receive $66 in cash, without interest, less any applicable withholding taxes. Completion of the merger is conditioned upon, among other things, the approval of certain state utility and other regulatory agencies. On November 19, 2015, the proposed merger was approved by our shareholders at a special meeting. At closing, the transaction is expected to create the second largest utility in the U.S. by customer base and we will become a wholly owned subsidiary of Southern Company and continue to maintain our own management team.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Director Independence

In accordance with the Standards for Determining Director Independence (the Standards), a director must be determined to have no material relationship with us other than as a director in order to be considered an independent director. The Standards specify the criteria by which the independence of our directors will be determined, including strict guidelines for directors and their immediate family members with respect to past employment or affiliation with us or our independent registered public accounting firm. The Standards also set forth independence criteria applicable to members of the Audit Committee, the Compensation Committee and the Nominating, Governance and Corporate Responsibility Committee of the Board. The Standards are available on our website at www.aglresources.com.

In accordance with the Standards, the Board undertook its annual review of director independence. Based on this review, the Board has affirmatively determined that, as to each current non-employee director, no material relationship exists that would interfere with the exercise of independent judgment in carrying out the responsibilities of a director

and that each current non-employee director qualifies as "independent" in accordance with the Standards and the independence standards of the New York Stock Exchange.
In making these independence determinations, the Board considered that in the ordinary course of business, transactions may occur between us and our subsidiaries and companies at which some of our directors are or have been directors, officers or employees. The Board also considered that we and our subsidiaries may make charitable contributions to not-for-profit organizations where our directors or their immediate family members serve or are executive officers.
Policy on Related Person Transactions
The Board recognizes that related person transactions present a heightened risk of conflicts of interest and, therefore, has adopted a written policy with respect to related person transactions. For the purpose of the policy, "Related Persons" include (i) each executive officer as defined under Section 16 of the Securities Exchange Act of 1934, as amended, or the "Exchange Act," (ii) each executive and senior vice president of the company, (iii) each nominee for or member of the Board, (iv) each holder of more than 5% of our common stock, or a "Significant Shareholder," and (v) any immediate family member, as defined under the Exchange Act, of the persons listed in (i) through (iv) above. A "Related Person Transaction" is a transaction between us and any Related Person, other than (a) transactions available to all employees or customers generally;
(b) transactions involving less than $120,000 when aggregated with all similar transactions since January 1, 2015;

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(c) transactions excluded from disclosure in paragraphs four through seven of the instructions to Item 404(a) of Regulation S-K under the Exchange Act; and (d) charitable contributions by us to a charitable organization with which a Related Person's only relationship is as an employee (other than an executive officer), if the aggregate amount involved does not exceed the greater of $1 million or 2% of the charitable organization's annual receipts for the preceding fiscal year.

Under the policy, when management becomes aware of a Related Person Transaction involving a dollar amount that is less than 2% of either our consolidated gross revenues or the consolidated gross revenues of the Related Person, or any affiliate of such Related Person, for the prior fiscal year, management reports the transaction to the Chair of the Nominating, Governance and Corporate Responsibility Committee. When management becomes aware of a Related Person Transaction involving a dollar amount that is equal to or exceeds 2% of either our consolidated gross revenues or the consolidated gross revenues of the Related Person, or any affiliate of such Related Person, for the prior fiscal year, management reports the transaction to the Nominating, Governance and Corporate Responsibility Committee and requests approval or ratification of the transaction.

Certain Relationships and Related Transactions

Since January 1, 2015, there have been no related party transactions required to be disclosed pursuant to Item 404 of Regulation S-K.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Audit and Non-Audit Fees

The following table summarizes certain fees billed by PricewaterhouseCoopers LLP for 2015 and 2014:

Fee Category	2015	2014
Audit fees	$3,967,025	$4,247,068
Audit-related fees	88,000	275,000
Tax fees	75,000	43,200
Total fees	$4,130,025	$4,565,268

Set forth below is a description of the nature of the services that PricewaterhouseCoopers LLP provided to us in exchange for such fees.

Audit Fees Represents fees PricewaterhouseCoopers LLP billed us for the audit of our annual financial statements, the review of our quarterly financial statements and services normally provided in connection with statutory and regulatory filings. These include fees incurred in meeting the internal control over financial reporting compliance requirements of Section 404 of the Sarbanes-Oxley Act of 2002, as well as fees for audits of several subsidiaries.

Audit-Related Fees Represents fees PricewaterhouseCoopers LLP billed us for audit and review-related services, including services relating to a review report on internal controls provided to third parties.

Tax Fees Represents fees PricewaterhouseCoopers LLP billed us for tax compliance, planning and advisory services.

The Audit Committee pre-approved all of the above audit, audit-related and tax fees of PricewaterhouseCoopers LLP, as required by the pre-approval policy described below.

Audit Committee Audit and Non-Audit Services Approval Policy

Consistent with rules and regulations pursuant to the Sarbanes-Oxley Act of 2002 regarding registered public accounting firm independence, the Audit Committee has responsibility for appointing, setting compensation and overseeing the work of our independent registered public accounting firm. In recognition of this responsibility, the Audit Committee adopted a policy that requires specific Audit Committee approval before any services are provided by the independent registered public accounting firm.

Prior to engagement of the independent registered public accounting firm for the next year's audit, management submits to the Audit Committee for approval a summary of services expected to be rendered during that year and an estimate of the related fees for (i) audit services, (ii) audit-related services, (iii) tax services, and (iv) all other services. The Audit Committee pre-approves these services by category of service and budget amount. The services and fees must be deemed compatible with the maintenance of the independent registered public accounting firm's independence. The Audit Committee requires the independent registered public accounting firm and management to report actual fees versus the budget periodically throughout the year by category of service. During the year, circumstances may arise when it may become necessary to engage the independent registered public accounting firm for additional services not contemplated in the original pre-approval. In those instances, the Audit Committee requires that management obtain specific approval from the Audit Committee before engaging the independent registered public accounting firm.

The Audit Committee may delegate approval authority to one or more of its members. The member to whom such authority is delegated must present for ratification any approval decisions to the Audit Committee at its next scheduled meeting.

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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 Balance Sheets as of December 31, 2015 and 2014
- Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Equity for the years ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013
- 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, 2015. 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, dated August 23, 2015, by and among The Southern Company, AMS Corp. and AGL Resources Inc.	AGL Resources	August 24, 2015, Form 8-K, Exhibit 2.1
3.1	Amended and Restated Articles of Incorporation	AGL Resources	May 4, 2015, Form 8-K, Exhibit 3.1
3.2	Bylaws, as amended	AGL Resources	May 4, 2015, Form 8-K, Exhibit 3.2
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 6.375% Senior Notes due 2016	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.1
4.3.b	Guarantee of AGL Resources Inc. dated December 14, 2007	AGL Resources	December 14, 2007, Form 8-K, Exhibit 4.2
4.4.a	AGL Capital Corporation 5.25% Senior Notes due 2019	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.1
4.4.b	Guarantee of AGL Resources Inc. dated August 10, 2009	AGL Resources	August 10, 2009, Form 8-K, Exhibit 4.2
4.5.a	AGL Capital Corporation 5.875% Senior Notes due 2041	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.1
4.5.b	Guarantee of AGL Resources Inc. dated March 21, 2011	AGL Resources	March 21, 2011, Form 8-K, Exhibit 4.2
4.6.a			

	Form of AGL Capital Corporation 3.50% Senior Notes due 2021	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.1
4.6.b	Form of Guarantee of AGL Resources Inc. dated September 2011	AGL Resources	September 20, 2011, Form 8-K, Exhibit 4.2
4.7.a	Form of AGL Capital Corporation Series A Senior Notes due 2016	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.1
4.7.b	Form of AGL Capital Corporation Series B Senior Notes due 2018	AGL Resources	September 7, 2011, Form 8-K, Exhibit 4.2
4.8.a	AGL Capital Corporation 4.40% Senior Notes due 2043	AGL Resources	May 16, 2013, Form 8-K, Exhibit 4.2
4.8.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
4.8.c	AGL Capital Corporation 3.875% Senior Notes due 2025	AGL Resources	November 18, 2015, Form 8-K, Exhibit 4.2
4.8.d	AGL Resources Inc. Guarantee related to the 3.875% Senior Notes due 2025	AGL Resources	November 18, 2015, Form 8-K, Exhibit 4.3
4.9.a	Indenture dated December 1, 1989	Atlanta Gas Light	File No. 33-32274, Form S-3, Exhibit 4(a)
4.9.b	First Supplemental Indenture dated March 16, 1992	Atlanta Gas Light	File No. 33-46419, Form S-3, Exhibit 4(a)

4.10	Indenture dated February 20, 2001	AGL Resources	September 17, 2001, File No. 333-69500, Form S-3, Exhibit 4.2
4.11.a	Indenture dated January 1, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.01
4.11.b	Indenture of adoption dated February 9, 1954	Nicor Gas	December 31, 1995, Form 10-K, Exhibit 4.02
4.11.c	Supplemental Indenture dated February 15, 1998	Nicor Gas	December 31, 1997, Form 10-K, Exhibit 4.19
4.11.d	Supplemental Indenture dated May 15, 2001	Nicor Gas	July 20, 2001, File No. 333-65486, Form S-3, Exhibit 4.18
4.11.e	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.09
4.11.f	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.10
4.11.g	Supplemental Indenture dated December 1, 2003	Nicor Gas	December 31, 2003, Form 10-K, Exhibit 4.11
4.11.h	Supplemental Indenture dated December 1, 2006	Nicor Gas	December 31, 2006, Form 10-K, Exhibit 4.11
4.11.i	Supplemental Indenture dated August 1, 2008	Nicor Gas	September 30, 2008, Form 10-Q, Exhibit 4.01
4.11.j	Supplemental Indenture dated July 23, 2009	Nicor Gas	June 30, 2009, Form 10-Q, Exhibit 4.01
4.11.k	Supplemental Indenture dated February 1, 2011	Nicor Gas	December 31, 2010, Form 10-K, Exhibit 4.12
4.11.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+	Amended and Restated Common Stock Equivalent Plan for Non-Employee Directors	AGL Resources	June 30, 2015, Form 10-Q, Exhibit 10.3
10.1.c+	Form of Stock Award Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.aj
10.1.d+	Form of Nonqualified Stock Option Agreement for Non-Employee Directors	AGL Resources	December 31, 2004, Form 10-K, Exhibit 10.1.ak
10.1.e+	Form of Director Indemnification Agreement dated April 28, 2004	AGL Resources	June 30, 2004, Form 10-Q, Exhibit 10.3
10.1.f+	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.g+	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.h+	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.i+	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.j+	Omnibus Performance Incentive Plan, as amended and restated	AGL Resources	March 14, 2011, Schedule 14A, Annex A
10.1.k+	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.l+	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.m+	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.n+	2007 Omnibus Performance Incentive Plan	AGL Resources	March 19, 2007, Schedule 14A, Annex A
10.1.o+	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.p+	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.q+	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.r+	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.s+	Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP)	AGL Resources	March 18, 2005, Form 8-K, Exhibit 10.1
10.1.t+	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.u+	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.v+	First Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.aa
10.1.w+	Second Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ab

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10.1.x+	Third Amendment to the Nonqualified Savings Plan	AGL Resources	December 31, 2013, Form 10-K, Exhibit 10.1.ac
10.1.y+	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.z+	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.aa+	Form of Continuity Agreement dated December 19, 2013	AGL Resources	December 19, 2013, Form 8-K, Exhibit 10.1
10.1.ab+	Description of compensation for each of John W. Somerhalder II, Andrew W. Evans, Elizabeth W. Reese, Henry P. Linginfelter, Paul R. Shlanta and Peter I. Tumminello (our Named Executive Officers for the year ended December 31, 2015)	AGL Resources	Compensation Discussion and Analysis section under Item 11 of the Form 10-K for December 31, 2015.
10.2.a	Form of Commercial Paper Dealer Agreement	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.79
10.2.b	Guarantee dated October 5, 2000 of payments on promissory notes	AGL Resources	September 30, 2000, Form 10-K, Exhibit 10.80
10.4	Note Purchase Agreement dated August 31, 2011	AGL Resources	September 7, 2011, Form 8-K, Exhibit 10.1
10.5	Final Allocation Agreement dated January 3, 2008	Nicor	December 31, 2007, Form 10-K, Exhibit 10.64
10.6	Second Amended and Restated Limited Liability Company Agreement of SouthStar Energy Services LLC dated September 6, 2013 by and between Georgia Natural Gas Company and Piedmont Energy Company	AGL Resources	September 30, 2013, Form 10-Q, Exhibit 10
10.7	Credit Agreement dated as of December 15, 2011	AGL Resources	December 15, 2011, Form 8-K, Exhibit 10.1
10.7a	First Amendment to Credit Agreement, dated as of February 26, 2013	AGL Resources	June 30, 2015, Form 10-Q, Exhibit 10.2
10.8	Amended and Restated Credit Agreement dated as of November 10, 2011	AGL Resources	November 17, 2011, Form 8-K, Exhibit 10.1
10.8.b	Second Amendment and Extension Agreement dated as of October 30, 2015	AGL Resources	November 5, 2015, Form 8-K, Exhibit 10.1
10.8.c	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
10.9.a	First Amendment to Bank Rate Mode Covenants Agreement dated as of October 30, 2015	AGL Resources	November 5, 2015, Form 8-K, Exhibit 10.3
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			March 27, 2013, Form 8-K, Exhibit 10.4

	Amended and Restated Loan Agreement dated as of March 1, 2013	AGL Resources	
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 Andrew W. Evans	AGL Resources	Filed herewith
31.2	Certification of Elizabeth W. Reese	AGL Resources	Filed herewith
32.1	Certification of Andrew W. Evans	AGL Resources	Filed herewith
32.2	Certification of Elizabeth W. Reese	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.

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(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, 2016.

AGL RESOURCES INC.

By: /s/ Andrew W. Evans

Andrew W. Evans

President and Chief Executive Officer

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Andrew W. Evans, Elizabeth W. Reese, 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, 2015, 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, 2016.

Signatures	Title
/s/ Andrew W. Evans Andrew W. Evans	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ Elizabeth W. Reese Elizabeth W. Reese	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, 2015.

In millions	Balance at beginning of period	Additions Charged to costs and expenses	Charged to other accounts	Deductions		Balance at end of period
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
2015						
Allowance for uncollectible accounts	$35	$27	$3	$(36	)	$29
Income tax valuation	20	—	—	(1	)	19

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