AGL RESOURCES INC
Form 10-K
February 04, 2010

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2009

OR

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

For the transition period from to

Commission File Number 1-14174

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

Georgia	58-2210952
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Ten Peachtree Place NE, Atlanta, Georgia 30309	404-584-4000
(Address and zip code of principal executive offices)	(Registrant's telephone number, including area code)

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 under the Securities Act. Yes þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or

Section 15(d) of the Securities Act. Yes ¨ No þ

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

(Do not check if smaller reporting company)

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

The aggregate market value of the registrant's voting and non-voting common equity held by non-affiliates of the registrant, computed by reference to the price at which the registrant's common stock was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter, was $2,458,113,574.

The number of shares of the registrant's common stock outstanding as of January 29, 2010 was 77,543,821.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2010 Annual Meeting of Shareholders ("Proxy Statement") to be held April 27, 2010, are incorporated by reference in Part III.

Glossary of Key Terms

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GLOSSARY OF KEY TERMS

AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
Atlanta Gas Light	Atlanta Gas Light Company
Bcf	Billion cubic feet
Chattanooga Gas	Chattanooga Gas Company
Credit Facility	$1.0 billion credit agreement of AGL Capital
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income and other income and excludes financing costs, including interest and debt and income tax expense each of which we evaluate on a consolidated level; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, earnings before income taxes, or net income attributable to AGL Resources Inc. as determined in accordance with GAAP
ERC	Environmental remediation costs associated with our distribution operations segment which are recoverable through rates mechanisms
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
GNG	Georgia Natural Gas, the name under which SouthStar does business in Georgia
Golden Triangle Storage	Golden Triangle Storage, Inc.
Heating Degree Days	A measure of the effects of weather on our businesses, calculated when the average daily actual temperatures are less than a baseline temperature of 65 degrees Fahrenheit.
Heating Season	The period from November to March when natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems when weather is colder
Henry Hub	A major interconnection point of natural gas pipelines in Erath, Louisiana where NYMEX natural gas future contracts are priced.
Jefferson Island	Jefferson Island Storage & Hub, LLC
LNG	Liquefied natural gas
LOCOM	Lower of weighted average cost or current market price
Magnolia	Magnolia Enterprise Holdings, Inc.
Maryland Commission	Maryland Public Service Commission, the state regulatory agency for Elkton Gas.
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Mcf	Million cubic feet
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.

NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A measure of income, calculated as operating revenues minus cost of gas, that excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our consolidated statements of income. Operating margin should not be considered an alternative to, or more meaningful than, operating income as determined in accordance with GAAP
OTC	Over-the-counter
Piedmont	Piedmont Natural Gas
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PP&E	Property, plant and equipment
S&P	Standard & Poor's Ratings Services
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.
SouthStar	SouthStar Energy Services LLC
Tennessee Authority	Tennessee Regulatory Authority, the state regulatory agency for Chattanooga Gas.
VaR	Value at risk is defined as the maximum potential loss in portfolio value over a specified time period that is not expected to be exceeded within a given degree of probability
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission, the state regulatory agency for Virginia Natural Gas.
WACOG	Weighted average cost of goods
WNA	Weather normalization adjustment

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PART I

ITEM 1. BUSINESS

Nature of Our Business

Unless the context requires otherwise, references to “we,” “us,” “our,” the “company” and “AGL Resources” are intended to mean consolidated AGL Resources Inc. and its subsidiaries.

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve approximately 2.3 million end-use customers. We are also involved in several related and complementary businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability natural gas storage assets. We also own and operate a small telecommunications business that constructs and operates conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through four operating segments and a nonoperating corporate segment.

Distribution Operations

Our distribution operations segment is the largest component of our business and includes six natural gas local distribution utilities. These utilities construct, manage and maintain intrastate natural gas pipelines and distribution facilities and include:

- Atlanta Gas Light in Georgia
- Chattanooga Gas in Tennessee
- Elizabethtown Gas in New Jersey
- Elkton Gas in Maryland
- Florida City Gas in Florida
- Virginia Natural Gas in Virginia

Regulatory Planning

Each utility operates subject to regulations of the state regulatory agencies in its service territories 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. Rates are set at levels that generally should allow recovery of 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 utility plant in service, working capital and certain other assets; less accumulated depreciation on utility plant in service and net deferred income tax liabilities, and may include certain other additions or deductions.

For our largest utility, Atlanta Gas Light, the natural gas market was deregulated in 1997. Prior to this, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today, Marketers sell natural gas to end-use customers in Georgia and handle customer billing functions. The Marketers file their rates monthly with the Georgia Commission. 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
- planning and contracting for capacity on interstate transportation and storage systems

Atlanta Gas Light recognizes revenue under a straight-fixed-variable rate design whereby it charges rates to its customers based primarily on monthly fixed charges that are periodically adjusted. The Marketers bill these charges directly to their customers. This mechanism minimizes the seasonality of Atlanta Gas Light's revenues since the monthly fixed charge is not volumetric or directly weather dependent. However, weather indirectly influences the number of customers that have active accounts during the heating season, and this has a seasonal impact on Atlanta Gas Light's revenues since generally more customers are connected in periods of colder weather than in periods of warmer weather.

All of our utilities, excluding Atlanta Gas Light, are authorized to use a natural gas cost recovery mechanism that allows them to adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure they recover 100% of the costs incurred in purchasing gas for their customers. Since Atlanta Gas Light does not sell natural gas directly to its end-use customers, it does not need or utilize a natural gas cost recovery mechanism.

Regulatory Agreements Over the past several years our utilities have been fulfilling their long-term commitments to rate freezes, which began expiring in 2009. In 2009 we filed rate cases for Elizabethtown Gas and Chattanooga Gas which included reforms that encourage conservation and "decoupling." In traditional rate designs, our utilities' recovery of a significant portion of their fixed customer service costs is tied to assumed natural gas volumes used by our customers. We believe separating, or decoupling, the recovery of these fixed costs from the natural gas deliveries will align the interests of our customers and utilities by encouraging energy conservation and ensuring stable returns for our shareholders.

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In March 2009, Elizabethtown Gas filed a rate case requesting an annual increase to base rates of $25 million. The filing also included energy conservation programs and a proposed Efficiency Usage and Adjustment mechanism (EUA), which is a form of decoupling. In June 2009, and in accordance with the New Jersey rate case rules that require the filing of quarterly updates to a case, we filed a revised request for a $17 million annual increase to base rates. The primary driver of the reduced request was a revision to depreciation rates.

In December 2009, the New Jersey BPU approved an agreement with Elizabethtown Gas regarding its base rate filing and the energy conservation programs. Under the terms of the agreement, Elizabethtown Gas received an increase in base rates which equates to approximately $3 million on an annual basis. Additionally, Elizabethtown Gas will reduce its overall composite depreciation rate from 3.20% to 2.58%, which equates to an annual reduction in depreciation expenses of approximately $5 million. The agreement includes a two-year freeze on base rates except as may be adjusted in the second phase of our rate case, in which the New Jersey BPU will consider, among other things, our request for the EUA.

In November 2009, Chattanooga Gas filed a rate case with the Tennessee Authority requesting an annual increase to base rates of approximately $3 million. The rate case proposal includes energy-efficiency and conservation programs, as well as a mechanism to recover lost revenue resulting from these programs. A decision by the Tennessee Authority is expected in the second quarter of 2010.

The following table provides regulatory information for our largest utilities.

	Atlanta Gas Light (9)	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
Authorized return on rate base (1)	8.53 %	7.64 %	9.24 %	7.36 %	7.89 %
Estimated 2009 return on rate base (2) (3)	7.39 %	6.55 %	8.80 %	4.47 %	6.86 %
Authorized return on equity (1)	10.90 %	10.30 %	10.90 %	11.25 %	10.20 %
Estimated 2009 return on equity (2) (3)	8.52 %	8.02 %	10.68 %	4.81 %	7.90 %
Authorized rate base % of equity (1)	47.9 %	47.9 %	52.4 %	36.8 %	44.8 %
Rate base included in 2009 return on equity (in millions) (3) (4)	$ 1,323	$ 448	$ 442	$ 153	$ 105
Performance based rates (5)			ü		
Weather normalization (6)		ü	ü		ü
Decoupled or straight-fixed variable rates (7)	ü		ü		
Current rates effective until (8)	Q4 2010	N/A	Q3 2011	N/A	Q2 2010

(1) The authorized return on rate base, return on equity, and percentage of equity were those authorized as of December 31, 2009.
(2) Estimates based on principles consistent with utility ratemaking in each jurisdiction, and are not necessarily consistent with GAAP returns.
(3) Florida City Gas includes the impacts of the acquisition adjustment, as approved by the Florida Commission in December 2007, in its rate base, return on rate base and return on equity calculations.
(4) Estimated based on 13-month average.
(5) Involves frozen rates for a determined period.
(6) Involves regulatory mechanisms that allow us to recover our costs in the event of unseasonal weather, but are not direct offsets to the potential impacts of weather and customer consumption on earnings. These mechanisms are

designed to help stabilize operating results by increasing base rate amounts charged to customers when weather is warmer than normal and decreasing amounts charged when weather is colder than normal.

(7) Decoupled and straight-fixed variable rate designs allow for the recovery of fixed customer service costs separately from assumed natural gas volumes used by our customers.

(8) Subject to change.

(9) In July 2009, Atlanta Gas Light filed a request with the Georgia Commission to postpone its scheduled filing of a rate case in November 2009. This request was approved by the Georgia Commission, which agreed to postpone the filing until April 1, 2010, but no later than June 1, 2010.

Competition and Customer Demand

All of our utilities face competition from other energy products. Our principal competition is from electric utilities and oil and propane providers serving the residential and commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the prices for competing sources of energy as compared to natural gas and the desirability of natural gas heating versus alternative heating sources.

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

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

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Due to the current general economic downturn and the decline in the housing markets in the areas we serve, customer growth declined slightly in our distribution operations segment in 2009 relative to 2008, a trend we expect to continue through 2010. For the year ended December 31, 2009, our year-over-year consolidated utility customer growth rate was slightly negative or (0.3)%, compared to 0.1% positive growth for 2008. We anticipate overall customer growth in 2010 to be flat to negative, primarily as a result of continued slow growth in the residential housing markets throughout most of our service territories and the effects of a weak economy on our commercial and industrial customers. In addition, we continue to experience some customer loss because of competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric alternatives.

The weak economy is expected to continue to impact a significantly larger portion of consumer household incomes during the current winter heating season. However, natural gas prices and the WACOG of our natural gas inventories have declined significantly since last year, which is expected to result in lower average customer bills and no significant increases in our bad debt expenses.

We work with regulators and state agencies in each of our jurisdictions to educate customers throughout the year about energy costs in advance of the winter heating season, and to ensure that those customers qualifying for the Low Income Home Energy Assistance Program and other similar programs receive any needed assistance and we expect to continue this focus for the foreseeable future. We have also worked with the Virginia Commission and the New Jersey BPU during 2009 to launch energySMART (Save Money and Resources Today) programs in Virginia and New Jersey to educate our customers about energy efficiency and conservation and to provide rebates and other incentives for the purchase of high-efficiency natural gas-fueled equipment.

We continue to use a variety of targeted marketing programs to attract new customers and to retain existing customers. These efforts include working to add residential customers, multifamily complexes and commercial customers who use natural gas for purposes other than space heating, as well as evaluating and launching new programs, products and services to enhance customer growth and operating revenues. In addition, we partner with numerous entities 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.

Capital Projects

In October 2009, Atlanta Gas Light received approval from the Georgia Commission for the Strategic Infrastructure Development and Enhancement (STRIDE) program. The Georgia Commission’s approval included the program’s initial three years’ expenditures, estimated at approximately $176 million. The purpose of STRIDE is to upgrade Atlanta Gas Light's distribution system and liquefied natural gas facilities in Georgia, improve system reliability, and create a platform to meet operational flexibility needs and forecasted growth. Under the program, Atlanta Gas Light would be required to file a ten-year infrastructure plan every three years for review and approval by the Georgia Commission. The program merges with Atlanta Gas Light’s existing pipeline replacement program, which was initiated in 1998 and is scheduled to end in December 2013. In January 2010, the Georgia Commission approved up to an additional $45 million of expenditures under the STRIDE program to extend Atlanta Gas Light’s pipeline facilities to serve customers without pipeline access and create new economic development.

In April 2009, the New Jersey BPU approved an accelerated $60 million enhanced infrastructure program for Elizabethtown Gas which started this year and is scheduled to be completed in 2011. This program was created in response to the New Jersey Governor’s request for utilities to assist in the economic recovery by increasing infrastructure investments. A regulatory cost recovery mechanism will be established with estimated rates put into effect at the beginning of each year. At the end of the program the regulatory cost recovery mechanism will be trued-up and any remaining costs not previously collected will be included in base rates. Elizabethtown Gas expects that approximately $36 million in capital expenditures for this program will occur in 2010.

In November 2009, we completed our $43 million Magnolia pipeline project in Georgia that will enable us to diversify our sources of natural gas through more access to natural gas supplies from Southern Natural Gas' Elba Island LNG terminal located on Georgia's Atlantic coast near Savannah. This project should provide increased reliability of service in the event that supplies coming from the Gulf Coast are disrupted.

Collective Bargaining Agreements

The following table provides information about our natural gas utilities' collective bargaining agreements. These agreements represent approximately 12% of our total employees.

	# of Employees	Contract Expiration Date
Virginia Natural Gas		
International Brotherhood of Electrical Workers (Local No. 50)	125	May 2010
Elizabethtown Gas		
Utility Workers Union of America (Local No. 424)	168	Nov. 2011
Total	293	

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Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture currently owned 85% by our subsidiary, Georgia Natural Gas Company, and 15% by Piedmont. SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers on an unregulated basis, primarily in Georgia as well as Ohio and Florida. In addition, SouthStar markets gas to larger commercial and industrial customers in Alabama, Tennessee, North Carolina, South Carolina and Georgia. Based on its market share, SouthStar is the largest Marketer of natural gas in Georgia, with average customers in excess of 500,000 over the last three years.

Prior to January 1, 2010, we owned a 70% interest in SouthStar and Piedmont owned 30%. However, in July 2009, we entered into an amended joint venture agreement with Piedmont pursuant to which we purchased an additional 15% ownership interest for $58 million, effective January 1, 2010, thus increasing our interest to 85%. This purchase will affect our consolidated statements of financial position, but will not result in a gain or loss on our consolidated statements of income. Prior to the effectiveness of our ownership increase, SouthStar's earnings for customers in Georgia were allocated 75% to us and 25% to Piedmont, while its earnings for customers in Ohio and Florida were allocated 70% to us and 30% to Piedmont. Earnings are now allocated entirely in accordance with the ownership interests. We have no contractual rights to acquire Piedmont's remaining 15% ownership interests. The amended agreement was approved by the Georgia Commission in October 2009.

SouthStar is governed by an executive committee, which is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under a joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 85% financial interest is considered to be noncontrolling. We record the earnings allocated to Piedmont as a noncontrolling interest in our consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a noncontrolling interest in our consolidated statements of financial position.

SouthStar's operations are sensitive to seasonal weather, natural gas prices, customer growth and consumption patterns similar to those affecting our utility operations. SouthStar's retail pricing strategies and the use of a variety of hedging strategies, such as 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 - Commodity Price Risk."

Competition SouthStar competes with other energy Marketers to provide natural gas and related services to customers in Georgia and the Southeast. In the Georgia market, SouthStar continues to experience the negative impact to operating margins from increased competition and an increase in the number of customers seeking the most competitive price plans. In addition, similar to our distribution operations, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. Also, price volatility in the wholesale natural gas commodity market has contributed to an increase in competition for residential and commercial customers.

SouthStar continues to use a variety of targeted marketing programs to attract new customers and to retain existing ones. Despite these efforts we have seen a 4% decline in average customer count for the year ended December 31, 2009, as compared to 2008. We believe this decline reflects some of the same economic conditions that have affected our utility businesses as well as the more competitive retail pricing market for natural gas in Georgia.

SouthStar may also be affected by the conservation and bad debt trends, but its overall exposure is partially mitigated by the high credit quality of SouthStar's customer base, lower wholesale natural gas prices in 2009, disciplined collection practices and the unregulated pricing structure in Georgia.

SouthStar continues to expand its business in other states as well. We are currently focusing these efforts on the Ohio and Florida markets.

Operating margin SouthStar generates operating margin primarily in three ways. The first is through the sale of natural gas to residential, commercial and industrial customers, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second is through the collection of monthly service fees and customer late payment fees.

SouthStar evaluates the combination of these two retail price components to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, customer service and billing, and lost and unaccounted-for gas, and to provide a reasonable profit, as well as being competitive to attract new customers and maintain market share. SouthStar's operating margin is affected by seasonal weather, natural gas prices, customer growth and their related market share in Georgia, which has historically been in excess of approximately 33%, based on customer count. SouthStar employs strategies to attract and retain a higher credit-quality customer base. These strategies result not only in higher operating margin, as these customers tend to utilize higher volumes of natural gas, but also help to mitigate bad debt expense due to the higher credit-quality of these customers.

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The third way SouthStar generates operating margin is through its commercial operations of optimizing storage and transportation assets and effectively managing commodity risk, which enables SouthStar to maintain competitive retail prices and operating margin. SouthStar is allocated storage and pipeline capacity that is used to supply natural gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices using natural gas storage transactions to capture operating margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes but prohibit the use of derivative instruments for speculative purposes.

Wholesale Services

Our wholesale services segment consists primarily of Sequent, our subsidiary involved in asset management and optimization, storage, transportation, producer and peaking services and wholesale marketing. Sequent seeks asset optimization opportunities, which focus on capturing the value from idle or underutilized assets, typically by participating in transactions to take advantage of pricing differences between varying markets and time horizons within the natural gas supply, storage and transportation markets to generate earnings. These activities are generally referred to as arbitrage opportunities.

Sequent's profitability is driven by volatility in the natural gas marketplace. Volatility arises from a number of factors such as weather fluctuations or the change in supply of, or demand for, natural gas in different regions of the country. Sequent seeks to capture value from the price disparity across geographic locations and various time horizons (location and seasonal spreads). In doing so, Sequent also seeks to mitigate the risks associated with this volatility and protect its margin through a variety of risk management and economic hedging activities.

Sequent provides its customers with natural gas from the major producing regions and market hubs in the U.S. and Canada. Sequent acquires transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its customers.

Storage inventory outlook Sequent's expected natural gas withdrawals are presented in the following table along with the operating revenues expected at the time of withdrawal. Sequent's expected operating revenues are net of the estimated impact of regulatory profit sharing under our asset management agreements and reflect the amounts that are realizable in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2009. A portion of Sequent's storage inventory is economically hedged with futures contracts, which results in realization of a substantially fixed margin, timing notwithstanding.

	Withdrawal schedule (in Bcf) – from reservoir storage (WACOG $3.55)	Expected operating revenues (in millions)
2010		
First quarter	16	$ 24
Second quarter	2	4
Third quarter	1	2
Total	19	$ 30

Expected operating revenues will change in the future as Sequent injects natural gas into inventory, adjusts its injection and withdrawal plans in response to changes in market conditions in future months and as forward NYMEX prices fluctuate. For more information on Sequent's energy marketing and risk management activities, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk - Commodity Price Risk."

Competition Sequent competes for asset management, long-term supply and seasonal peaking service contracts with other energy wholesalers, often through a competitive bidding process.

Asset Management Transactions Sequent's asset management customers include affiliated and nonaffiliated utilities, municipal utilities, power generators and large industrial customers. These customers, due to seasonal demand or levels of activity, may have contracts for transportation and storage capacity which exceed their actual requirements. Sequent enters into structured agreements with these customers, whereby Sequent, on behalf of the customers, optimizes the transportation and storage capacity during periods when customers do not use it for their own needs. Sequent may capture incremental operating margin through optimization, and either share margins with the customers or pay them a fixed amount.

Sequent has entered into asset management agreements with our affiliated utilities that include profit sharing mechanisms and fixed fee payments that require Sequent to make aggregate annual minimum payments of $14 million. These agreements are scheduled to expire over the next three years. The following table provides payments made under these agreements during the last three years.

	Profit sharing / fee payments		
In millions	2009	2008	2007
Atlanta Gas Light	$ 16	$ 9	$ 9
Elizabethtown Gas	11	5	6
Chattanooga Gas	4	4	2
Virginia Natural Gas	7	2	7
Florida City Gas	1	1	1
Total	$ 39	$ 21	$ 25

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Transportation Transactions Sequent contracts for natural gas transportation capacity and participates in transactions that manage the natural gas commodity and transportation costs in an attempt to achieve the lowest cost to serve its various markets. Sequent seeks to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation alternatives and markets to which it has access and identifying the lowest-cost alternatives to serve the various markets. This enables Sequent to capture geographic pricing differences across these various markets as delivered natural gas prices change.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions and lock-in a margin on future transportation activities. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives’ fair value in its reported operating results in the period of change, which can be in periods prior to actual utilization of the transportation capacity.

Producer Services Sequent’s producer services business primarily focuses on aggregating natural gas supply from various small and medium-sized producers located throughout the natural gas production areas of the United States. Sequent provides producers with certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid.

Natural Gas Storage Transactions Sequent purchases natural gas for storage when the current market price it pays plus the cost for transportation and storage is less than the market price it anticipates it could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio and uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or OTC derivatives in forward months to substantially lock in the operating revenue it will ultimately realize when the stored gas is actually sold.

We view Sequent’s trading margins from two perspectives. First, we base our commercial decisions on economic value, which is defined as the locked-in 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 that physical storage is settled. Second is the GAAP reported value both in periods prior to and in the period of physical withdrawal and sale of inventory. The GAAP amount is affected by the process of accounting for the financial hedging instruments in interim periods at fair value between the period when the natural gas is injected into storage and when it is ultimately withdrawn and the derivative financial instruments are settled. The change in the fair value of the hedging instruments is recognized in earnings in the period of change and is recorded as unrealized gains or losses. The actual value, less any interim recognition of gains or losses on hedges and adjustments for LOCOM, is realized when the natural gas is delivered to its ultimate customer.

Sequent accounts for natural gas stored in inventory differently than the derivatives Sequent uses to mitigate the commodity price risk associated with its storage portfolio. The natural gas that Sequent purchases and injects into storage is accounted for at the lower of average cost or current market value. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. This difference in accounting treatment can result in volatility in Sequent’s reported results, even though the expected operating revenue is essentially unchanged from the date the transactions were initiated. These accounting differences also affect the comparability of Sequent’s period-over-period results, since changes in forward NYMEX prices do not increase and decrease on a consistent basis from year to year.

Park and Loan Transactions Sequent routinely enters into park and loan transactions with various pipelines, which allow Sequent to park gas on, or borrow gas from, the pipeline in one period and reclaim gas from, or repay gas to, the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed in much the same way as traditional reservoir and salt dome storage transactions are evaluated and managed.

Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period, if the forward NYMEX prices in the months of delivery and receipt do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges. Once gas is delivered under the park and loan transaction, earnings volatility is essentially eliminated since the park and loan transaction contains an embedded derivative, which is also marked to market and would substantially offset subsequent changes in value of the forward NYMEX contracts used to hedge the park and loan transaction.

Energy Investments

Our energy investments segment includes a number of businesses that are related and complementary to our primary business. The most significant of these businesses is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome and other storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under a portfolio of short, medium and long-term contracts at a fixed market rate.

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Jefferson Island This wholly owned subsidiary operates a salt dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub and currently consists of two salt dome storage caverns with 7.5 Bcf of working gas capacity, 0.7 Bcf / day withdrawal capacity and 0.4 Bcf /day injection capacity. The storage facility is regulated by the Louisiana Department of Natural Resources and by the FERC, which has limited regulatory authority over storage and transportation services. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub and its interconnection with eight other pipelines in the area. Jefferson Island's entire portfolio is under firm subscription for the current heating season.

In December 2009, the Louisiana Mineral and Energy Board approved an operating agreement between Jefferson Island and the State of Louisiana. The new agreement enables us to resume our efforts to obtain the environmental, safety and other regulatory approvals needed to create two new storage caverns, which would expand the total working gas capacity of Jefferson Island to approximately 19.5 Bcf.

Golden Triangle Storage In 2008, our wholly-owned subsidiary, Golden Triangle Storage, started construction on a natural gas storage facility in the Gulf Coast region of Texas. The project will consist of two underground salt dome storage caverns that will hold about 12 Bcf of working natural gas storage capacity and total cavern capacity of 18 Bcf. The facility potentially can be expanded to a total of five caverns with 38 Bcf of working natural gas storage capacity in the future. It is also expected that Golden Triangle Storage will build an approximately nine-mile dual 24" natural gas pipeline to connect the storage facility with three interstate and three intrastate pipelines. We expect the first cavern with 6 Bcf of working capacity to be in service in the second half of 2010 and the second cavern with 6 Bcf of working capacity to be in service in mid 2012.

We estimate, based on current prices for labor, materials and pad gas, that costs to construct the facility will be approximately $314 million. The actual project costs depend upon the facility's configuration, materials, drilling costs, financing costs and the amount and cost of pad gas, which includes volumes of non-working natural gas used to maintain the operational integrity of the cavern facility. The costs for approximately 76% of these items have been fixed and are not subject to continued variability during construction. We are not able to predict whether these costs of construction will continue to increase, moderate or decrease from current levels, as there could be continued volatility in the construction cost estimates.

Competition Our natural gas storage facilities compete with natural gas facilities in the Gulf Coast region of the United States. All of the existing and proposed high deliverability salt dome natural gas storage facilities in North America are located in the Gulf Coast region.

AGL Networks This wholly owned subsidiary provides telecommunications conduit and available for use or "dark" fiber optic cable. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia, Phoenix, Arizona and Charlotte, North Carolina metropolitan areas, with a small presence in other cities in the United States. Its customers include local, regional and national telecommunications companies, internet service providers, educational institutions and other commercial entities. AGL Networks typically provides underground conduit and dark fiber to its customers under leasing arrangements with terms that vary from one to twenty years. In addition, AGL Networks offers telecommunications construction services to its customers. AGL Networks' competitors are any entities that have laid or will lay conduit and fiber on the same route as AGL Networks in the respective metropolitan areas.

Corporate

Our corporate segment includes our nonoperating business units. AGL Services Company is a service company we established to provide certain centralized shared services to our operating segments. We allocate substantially all of AGL Services Company's operating expenses and interest costs to our operating segments in accordance with state regulations.

AGL Capital, our wholly owned finance subsidiary, provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements. Our corporate segment also includes intercompany eliminations for transactions between our operating business segments. Our EBIT results include the impact of these allocations to the various operating segments.

Employees

As of January 29, 2010, we employed 2,469 employees, and we believe that our relations with them are good.

Additional Information

For additional information on our segments, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and "Note 9, Segment Information," set forth in Item 8, "Financial Statements and Supplementary Data."

Information on our environmental remediation efforts, is contained in "Note 7, Commitments and Contingencies," set forth in Item 8, "Financial Statements and Supplementary Data."

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Available Information

Detailed information about us is contained in our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and other reports, and amendments to those reports, that we file with, or furnish to, the SEC. These reports are available free of charge 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 - Dept. 1071
P.O. Box 4569
Atlanta, GA 30309-4569
404-584-4000

In Part III of this Form 10-K, we incorporate certain information by reference from our Proxy Statement for our 2010 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 18, 2010, and we will make it available on our website as soon as reasonably practicable. Please refer to the Proxy Statement when it is available.

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

ITEM 1A. RISK FACTORS

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain expectations and projections regarding our future performance referenced in this report, in other reports or proxy statements we file with the SEC or otherwise release to the public, and on our website are forward-looking statements. 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 involve matters that are not historical facts, such as statements in “Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations” and elsewhere regarding our future operations, prospects, strategies, financial condition, economic performance (including growth and earnings), industry conditions and demand for our products and services. We have tried, whenever possible, to identify these statements by using words such as "anticipate," "assume," “believe,” "can," "could," "estimate," "expect," "forecast," "future," “goal,” "indicate," "intend," "may," “outlook,” "plan," “potential,” "predict," "project,” "seek," "should," "target," "would," or similar expressions.

You are cautioned not to place undue reliance on our forward-looking statements. Our expectations are not guarantees and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations for the future are reasonable in view of the currently available information, our expectations are subject to future events, risks and uncertainties, and there are numerous factors - many beyond our control - that could cause results to differ significantly from our expectations. Such events, risks and uncertainties include, but are not limited to those set forth below and in the other documents that we file with the SEC. We note these factors for investors as permitted by the Private Securities Litigation Reform Act of 1995. There also may be other factors that we cannot anticipate or that are not described in this report, generally because we do not perceive them to be material, which could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not undertake any obligation to update these statements to reflect subsequent circumstances or events. You are advised, however, to review any further disclosures we make on related subjects in our Form 10-Q and Form 8-K reports to the SEC.

Risks Related to Our Business

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

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

These authorities regulate many aspects of our operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of costs associated with our regulatory infrastructure projects, including our pipeline replacement programs, and environmental remediation activities, relationships with our affiliates, and carrying costs we charge Marketers selling retail natural gas in Georgia for gas held in storage for their customer accounts. Our ability to obtain rate increases and rate supplements to maintain our current rates of return and recover regulatory assets and liabilities recorded in accordance with authoritative guidance related to regulated operations depends on regulatory discretion, and there can be no assurance that we will be able to obtain rate increases or rate supplements or continue receiving our currently authorized rates of return including the recovery of our regulatory assets and liabilities. In addition, if we fail to comply with applicable regulations, we could be subject to fines, penalties or other enforcement action by the authorities that regulate our operations, or otherwise be subject to material costs and liabilities.

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Deregulation in the natural gas industry is the separation of the provision and pricing of local distribution gas services into discrete components. Deregulation typically focuses on the separation of the gas distribution business from the gas sales business and is intended to cause the opening of the formerly regulated sales business to alternative unregulated suppliers of gas sales services.

In 1997, Georgia enacted legislation allowing deregulation of gas distribution operations. To date, Georgia is the only state in the nation that has fully deregulated gas distribution operations, which ultimately resulted in Atlanta Gas Light exiting the retail natural gas sales business while retaining its gas distribution operations. Marketers, including our majority-owned subsidiary, SouthStar, then assumed the retail gas sales responsibility at deregulated prices. The deregulation process required Atlanta Gas Light to completely reorganize its operations and personnel at significant expense. It is possible that the legislature could reverse or amend portions of the deregulation process.

Our business is subject to environmental regulation in all jurisdictions in which we operate, and our costs to comply are significant. Any changes in existing environmental regulation could affect our results of operations and financial condition.

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

In addition, claims against us under environmental laws and regulations could result in material costs and liabilities. Existing environmental regulations could also be revised or reinterpreted, new laws and regulations could be adopted or become applicable to us or our facilities, and future changes in environmental laws and regulations could occur. 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, particularly if those costs are not fully recoverable from our customers. Additionally, the discovery of presently unknown environmental conditions could give rise to expenditures and liabilities, including fines or penalties, which could have a material adverse effect on our business, results of operations or financial condition.

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

We must construct additions to our natural gas distribution system 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 this construction may be affected by the cost of obtaining government and other approvals, development project delays, adequacy of supply of diversified vendors, 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, and projected construction schedule and completion timeline of a project. Our cash flows may not be fully adequate to finance the cost of this construction. As a result, we may be required to fund a portion of our cash needs through borrowings or the issuance of common stock, or both. For our distribution operations segment, this may limit our ability to expand our infrastructure to connect new customers due to limits on the amount we can economically invest, which shifts costs to potential customers and may make it uneconomical for them to connect to our distribution systems. For our natural gas storage business, this may significantly reduce our earnings and return on investment from what would be expected for this business, or may impair our ability to complete the expansions or development projects.

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

Climate change is receiving ever increasing attention from scientists and legislators alike. The debate is ongoing as to the extent to which our climate is changing, the potential causes of this change and its potential impacts. Some attribute global warming to increased levels of greenhouse gases, including carbon dioxide, which has led to significant legislative and regulatory efforts to limit greenhouse gas emissions.

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Presently there are no federally mandated greenhouse gas reduction requirements in the United States. However, in June 2009 the U.S. House of Representatives passed bill H.R. 2454, American Clean Energy and Security Act of 2009, which proposes reducing greenhouse gas emissions to 17% below 2005 levels by 2020 and 83% below 2005 levels by 2050. The bill has now passed to the United States Senate for debate and vote. Consequently, the precise federal mandatory carbon dioxide emissions reduction program that may be adopted and the specific requirements of any such program are uncertain.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could:

- result in increased costs associated with our operations
- increase other costs to our business
- affect the demand for natural gas, and
- impact the prices we charge our customers.

Because natural gas is a fossil fuel with low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for production of electricity and direct use in homes and businesses.

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

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

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

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

The natural gas business is highly competitive, increasingly complex, and we are facing increasing competition from other companies that supply energy, including electric companies, oil and propane providers and, in some cases, energy marketing and trading companies. In particular, the success of our investment in SouthStar is affected by the competition SouthStar faces from other energy marketers providing retail natural gas services in the Southeast. 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 gas costs, could also cause these customers to bypass or disconnect from our systems in favor of special competitive contracts with lower per-unit costs.

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

The continuation of recent economic conditions could adversely affect our customers and negatively impact our financial results.

The slowdown in the U.S. economy, along with increased mortgage defaults, and significant decreases in new home construction, home values and investment assets, has adversely impacted the financial well-being of many U.S. households. We cannot predict if the administrative and legislative actions to address this situation will be successful in reducing the severity or duration of this recession. As a result, our customers may use less gas in future heating seasons and it may become more difficult for them to pay their natural gas bills. This may slow collections and lead to higher than normal levels of accounts receivables, bad debt and financing requirements.

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

We have accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At December 31, 2009, Atlanta Gas Light had nine certificated and active Marketers and one regulated natural gas provider in Georgia responsible for offering natural gas to low-income customers and customers unable to get natural gas service from other Marketers, four of which (based on customer count and including SouthStar) accounted for approximately 31% of our consolidated operating margin for 2009. As a result, Atlanta Gas Light depends on a concentrated number of customers for revenues. The provisions of Atlanta Gas Light's tariff allow it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill in the form of cash deposits, letters of credit, surety bonds or guaranties. The failure of these Marketers to pay Atlanta Gas Light could adversely affect Atlanta Gas Light's business and results of operations and expose it to difficulties in collecting Atlanta Gas Light's accounts receivable. AGL Resources provides a guarantee to Atlanta Gas Light as security support for SouthStar. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of severe cold weather or high prices for natural gas that increase customers' bills and, consequently, impair customers' ability to pay.

Sequent often extends credit to its counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, Sequent is exposed to the risk that it may not be able to collect amounts owed to it. If the counterparty to such a transaction fails to perform and any collateral Sequent has secured is inadequate, Sequent could experience material financial losses. Further, Sequent has a concentration of credit risk, which could subject a significant portion of its credit exposure to collection risks. Approximately 58% of Sequent's credit exposure is concentrated in its top 20 counterparties. 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 Sequent could result in credit losses that would negatively impact our wholesale services segment.

The asset management arrangements between Sequent and our local distribution companies, and between Sequent and its nonaffiliated 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, Chattanooga Gas, Elizabethtown Gas, Elkton Gas, Florida City Gas, and Virginia Natural Gas and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elkton Gas where Sequent is assessed annual fixed-fees payable in monthly installments. Entry into and renewal of these agreements are subject to regulatory approval and none are subject to renewal until 2011. In addition, Sequent has asset management agreements with certain nonaffiliated customers. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

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

The commodity, storage and transportation portfolios at Sequent and the commodity and storage portfolios at SouthStar consist of contracts to buy and sell natural gas commodities, including contracts that are settled by the delivery of the commodity or cash. If the values of these contracts change in a direction or manner that we do not anticipate, we could experience financial losses from our trading activities. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's and SouthStar's portfolio of positions as of December 31, 2009 had a 1-day holding period VaR of $2.4 million and less than $0.1 million, respectively.

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

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

Changes in weather conditions may affect our earnings.

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

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We have a WNA mechanism for Elizabethtown Gas and Chattanooga Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and our operating margin. At Elizabethtown Gas we could be required to return a portion of any WNA surcharge to its customers if Elizabethtown Gas' return on equity exceeds its authorized return on equity of 10%.

Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impact of unusually cold or warm weather. In September 2007, the Virginia Commission approved Virginia Natural Gas' application for an Experimental Weather Normalization Adjustment Rider (the Rider) for its commercial customers. The Rider applied to the 2007 and 2008 heating seasons. In September 2009 the Rider was extended to September 2011.

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

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

A decrease in the availability of adequate pipeline transportation capacity could reduce our revenues and profits.

Our gas supply depends on the availability of adequate pipeline transportation and storage capacity. We purchase a substantial portion of our gas supply from interstate sources. Interstate pipeline companies transport the gas to our system. A decrease in interstate pipeline capacity available to us or an increase in competition for interstate pipeline transportation and storage service could reduce our normal interstate supply of gas.

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

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

We could incur additional material costs for the environmental condition of some of our assets, including former manufactured gas plants.

We are generally responsible for all on-site and certain off-site 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.

We have confirmed ten sites in Georgia and three in Florida where we own all or part of an MGP site. One additional former MGP site has been recently identified adjacent to an existing MGP remediation site. Precise engineering soil and groundwater clean up estimates are not available and considerable variability exists with this potential new site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. As of December 31, 2009, the soil and sediment remediation program was substantially complete for all Georgia sites, except for a few remaining areas of recently discovered impact, although groundwater cleanup continues. As of December 31, 2009, projected costs associated with the MGP sites associated with Atlanta Gas Light range from $64 million to $113 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

In addition, we are associated with former sites in New Jersey, North Carolina and other states. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. For the New Jersey sites, cleanup cost estimates range from $69 million to $134 million. Costs have been estimated for only one of the non-New Jersey sites, for which current estimates range from $11 million to $16 million.

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

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

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Rapid increases in the price of purchased gas cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly during the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2010.

Finally, higher costs of natural gas in recent years have already caused many of our utility customers to conserve in the use of our gas services and could lead to even more customers utilizing such conservation methods or switching to other competing products. The higher costs have also allowed competition from products utilizing alternative energy sources for applications that have traditionally used natural gas, encouraging some customers to move away from natural gas fired equipment to equipment fueled by other energy sources.

The cost of providing pension and postretirement health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.

We have defined benefit pension and postretirement health care plans for the benefit of substantially all full-time employees and qualified retirees. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancy of beneficiaries and changes in health care cost trends.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension funds. In these circumstances, we may be required to recognize an increased pension expense or a charge to our other comprehensive income to the extent that the pension fund values are less than the total anticipated liability under the plans. Market declines in the second half of 2008 resulted in significant losses in the value of our pension fund assets. Although the market made a recovery in 2009 our pension fund assets are not at the levels they were prior to the market decline in 2008. As a result, based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $21 million in 2010. We are planning to make additional contributions in 2010 up to $17 million, for a total of up to $38 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of The Pension Protection Act of 2006 (Pension Protection Act). As of December 31, 2009 our pension plans assets represented 65% of our total pension plan obligations.

For more information regarding some of these obligations, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Contractual Obligations and Commitments"see and the subheading “Pension and Postretirement Obligations” and Note 3 “Employee Benefit Plans,” set forth in Item 8, “Financial Statements and Supplementary Data.”

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

Natural disasters may damage our assets. The threat of terrorism and the impact of retaliatory military and other action by the United States and its allies may lead to increased political, economic and financial market instability and volatility in the price of natural gas that could affect our operations. In addition, future acts of terrorism could be directed against companies operating in the United States, and companies in the energy industry may face a heightened risk of exposure to acts of terrorism. These developments have subjected our operations to increased risks. The insurance industry has also been disrupted by these events. As a result, the availability of insurance covering risks against which we and our competitors typically insure may be limited. In addition, the insurance we are able to obtain may have higher deductibles, higher premiums and more restrictive policy terms.

Risks Related to Our Corporate and Financial Structure

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

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

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

The continued disruption in the credit markets could limit our ability to access capital and increase our cost of capital.

The global credit markets experienced significant disruption and volatility in recent years. In some cases, the ability or willingness of traditional sources of capital to provide financing has been reduced.

Historically, we have accessed the commercial paper markets to finance our short-term working capital requirements, but the disruption in the credit markets limited our access to the commercial paper markets at reasonable interest rates in 2008. Consequently, we borrowed directly under our Credit Facility in 2008 for our working capital needs. While the commercial paper market has stabilized in 2009 and allowed us to repay the amounts borrowed directly from our Credit Facility, it has not returned to its pre-recession state. As of December 31, 2009, we had $601 million in commercial paper outstanding and no outstanding borrowings under our Credit Facility. During 2009, our borrowings under this facility along with our commercial paper were used primarily to purchase natural gas inventories for the current winter heating season. The amount of our working capital requirements in the near-term will depend primarily 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 facility to fund our operations.

While we believe we can meet our capital requirements from our operations and the sources of financing available to us, 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 of a continuation of current market conditions could be material and adverse to us, both in the ways described above, or in ways that we do not currently anticipate.

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

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

A downgrade in our credit rating could negatively affect our ability to access capital.

Our senior unsecured debt is currently assigned a rating of BBB+ by S&P, Baa1 by Moody's and A- by Fitch. Our commercial paper currently is rated A-2 by S&P, P-2 by Moody's and F2 by Fitch. 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 will be required to provide additional support for certain customers of our wholesale business. As of December 31, 2009, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $25 million to continue conducting our wholesale services business with certain counterparties.

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

We are subject to interest rate risk in connection with the issuance of fixed-rate and variable-rate debt. In order to maintain our desired mix of fixed-rate and variable-rate debt, we may use interest rate swap agreements and exchange fixed-rate and variable-rate interest payment obligations over the life of the arrangements, without exchange of the underlying principal amounts. For additional information, see Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to manage 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 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 cash in the form of dividends or other distributions from our subsidiaries to meet our cash requirements. The ability of our subsidiaries to pay dividends and make other distributions is subject to applicable state law. Refer to Item 5, “Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities” for additional dividend restriction information.

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

We use derivatives, including futures, 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 the absence of actively quoted market prices and pricing information from external sources, the valuation of these derivative financial 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 value of the reported fair value of these contracts.

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

Our Credit Facility under which our debt is issued contains cross-default provisions. Accordingly, should an event of default occur under some of our debt agreements, we face the prospect of being in default under other of our debt agreements, obligated in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

ITEM 1B. UNRESOLVED STAFF COMMENTS

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

ITEM 2. PROPERTIES

We consider our properties to be well maintained, in good operating condition and suitable for their intended purpose. The following provides the location and general character of the materially important properties that are used by our segments.

Distribution and transmission assets

This property primarily includes assets used by our distribution operations and energy investment segments for the distribution of natural gas to our customers in our service areas, and includes approximately 46,000 miles of underground distribution and transmission mains. These mains are located on easements or rights-of-way which generally provide for perpetual use.

Storage assets

We have approximately 7.5 Bcf of LNG storage capacity in five LNG plants located in Georgia, New Jersey and Tennessee. In addition, we own three propane storage facilities in Virginia and Georgia that have a combined storage capacity of approximately 1 Bcf. These LNG plants and propane facilities are used by distribution operations to supplement the natural gas supply during peak usage periods.

We also own a high-deliverability natural gas storage and hub facility in Louisiana. This facility is operated by a subsidiary within our energy investments segment and includes two salt dome gas storage caverns with approximately 10 Bcf of total capacity and about 8 Bcf of working gas capacity. Our energy investments segment also owns a propane storage facility in Virginia with approximately 0.3 Bcf of storage capacity. This facility supplements the natural gas supply to our Virginia utility during peak usage periods.

Telecommunications assets

AGL Networks, a subsidiary within our energy investments segment, owns and operates telecommunications conduit and fiber property in public rights-of-way that are leased to our customers primarily in Atlanta, Phoenix and Charlotte. This includes over 184,000 fiber miles, a 55,000 mile increase compared to 2008. Approximately 44% of our dark fiber in Atlanta, 25% of our dark fiber in Phoenix and 4% of our dark fiber in Charlotte has been leased.

Offices

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

Glossary of Key Terms

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 some of these proceedings, see Note 7 to our consolidated financial statements under the caption "Litigation."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the fourth quarter ended December 31, 2009.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

Name, age and position with the company	Periods served
John W. Somerhalder II, Age 54 (1)	
Chairman, President and Chief Executive Officer	October 2007 – Present
President and Chief Executive Officer	March 2006 – October 2007
Ralph Cleveland, Age 47	
Executive Vice President, Engineering and Operations	December 2008 – Present
Senior Vice President, Engineering and Operations	February 2005 – December 2008
Vice President, Engineering, Construction and Chief Engineer – Atlanta Gas Light	January 2003 – February 2005
Andrew W. Evans, Age 43	
Executive Vice President, Chief Financial Officer and Treasurer	June 2009 – Present
Executive Vice President and Chief Financial Officer	May 2006 – June 2009
Senior Vice President and Chief Financial Officer	September 2005 – May 2006
Vice President and Treasurer	April 2002 – September 2005
Henry P. Linginfelter, Age 49	
Executive Vice President, Utility Operations	June 2007 – Present
Senior Vice President, Mid-Atlantic Operations	November 2004– June 2007
Melanie M. Platt, Age 55	
Senior Vice President, Human Resources, Marketing and Communications	November 2008 – Present
Senior Vice President, Human Resources	September 2004 – November 2008
Douglas N. Schantz, Age 54	
President, Sequent	May 2003 – Present

Paul R. Shlanta, Age 52

Executive Vice President, General Counsel and Chief Ethics and Compliance Officer	September 2005 – Present
Senior Vice President, General Counsel and Chief Corporate Compliance Officer	September 2002 – September 2005

(1) Mr. Somerhalder was executive vice president of El Paso Corporation (NYSE: EP) from 2000 until May 2005, and he continued service under a professional services agreement from May 2005 until March 2006.

PART II

ITEM 5. MARKET FOR THE 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 symbol AGL. At January 29, 2010, there were 9,553 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2009 and 2008 is as follows:

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Quarter ended:	Sales price of common stock High	Low	Cash dividend per common share	Quarter ended:	Sales price of common stock High	Low	Cash dividend per common share
March 31, 2009	$ 34.93	$ 24.02	$ 0.43	March 31, 2008	$ 39.13	$ 33.45	$ 0.42
June 30, 2009	32.38	26.00	0.43	June 30, 2008	36.50	33.46	0.42
September 30, 2009	35.79	30.05	0.43	September 30, 2008	35.44	30.60	0.42
December 31, 2009	37.52	33.50	0.43	December 31, 2008	32.07	24.02	0.42
			$ 1.72				$ 1.68

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 248 consecutive quarterly dividends beginning in 1948. Our common shareholders may receive dividends when declared at the discretion of our Board of Directors. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources – Cash Flow from Financing Activities – Dividends on Common Stock." Dividends may be paid in cash, stock or other form of payment, and payment of future dividends will depend on our future earnings, cash flow, financial requirements and other factors, some of which are noted below. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

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

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

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

Issuer Purchases of Equity Securities

The following table sets forth information regarding purchases of our common stock by us and any affiliated purchasers during the three months ended December 31, 2009. Stock repurchases may be made in the open market or in private transactions at times and in amounts that we deem appropriate. However, there is no guarantee as to the exact number of additional shares that may be repurchased, and we may terminate or limit the stock repurchase program at any time. We currently anticipate holding the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2)	Average price paid per common share	Total number of shares purchased as part of publicly announced plans or programs (2)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (2)

October 2009	-	$ -	-	4,950,951
November 2009	-	-	-	4,950,951
December 2009	3,000	36.07	-	4,950,951
Total fourth quarter	3,000	$ 36.07	-	

(1) On March 20, 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock in the open market to be used for issuances under the Officer Incentive Plan (Officer Plan). We purchased 3,000 shares for such purposes in the fourth quarter of 2009. As of December 31, 2009, we had purchased a total 327,860 of the 600,000 shares authorized for purchase, leaving 272,140 shares available for purchase under this program.

(2) On February 3, 2006, we announced that our Board of Directors had authorized a plan to repurchase up to a total of 8 million shares of our common stock, excluding the shares remaining available for purchase in connection with the Officer Plan as described in note (1) above, over a five-year period.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources for the last five years is set forth in the table below. You should read the data in the table in conjunction with the consolidated financial statements and related notes set forth in Item 8, "Financial Statements and Supplementary Data."

Dollars and shares in millions, except per share amounts	2009	2008	2007	2006	2005
Income statement data					
Operating revenues	$ 2,317	$ 2,800	$ 2,494	$ 2,621	$ 2,718
Cost of gas	1,142	1,654	1,369	1,482	1,626
Operating margin (1)	1,175	1,146	1,125	1,139	1,092
Operating expenses					
Operation and maintenance	497	472	451	473	477
Depreciation and amortization	158	152	144	138	133
Taxes other than income taxes	44	44	41	40	40
Total operating expenses	699	668	636	651	650
Operating income	476	478	489	488	442
Other income (expense)	9	6	4	(1)	(1)
Earnings before interest and taxes (EBIT) (1)	485	484	493	487	441
Interest expense	101	115	125	123	109
Earnings before income taxes	384	369	368	364	332
Income taxes	135	132	127	129	117
Net income	249	237	241	235	215
Less net income attributable to the noncontrolling interest	27	20	30	23	22
Net income attributable to AGL Resources Inc.	$ 222	$ 217	$ 211	$ 212	$ 193
Common stock data					
Weighted average common shares outstanding basic	76.8	76.3	77.1	77.6	77.3
Weighted average common shares outstanding diluted	77.1	76.6	77.4	78.0	77.8
Total shares outstanding (2)	77.5	76.9	76.4	77.7	77.8
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.89	$ 2.85	$ 2.74	$ 2.73	$ 2.50
Diluted earnings per common share – attributable to AGL Resources Inc. common shareholders	$ 2.88	$ 2.84	$ 2.72	$ 2.72	$ 2.48
Dividends declared per common share	$ 1.72	$ 1.68	$ 1.64	$ 1.48	$ 1.30
Dividend payout ratio	60 %	59 %	60 %	54 %	52 %
Dividend yield (3)	4.7 %	5.4 %	4.4 %	3.8 %	3.7 %
Price range:					
High	$ 37.52	$ 39.13	$ 44.67	$ 40.09	$ 39.32
Low	$ 24.02	$ 24.02	$ 35.24	$ 34.40	$ 32.00
Close (2)	$ 36.47	$ 31.35	$ 37.64	$ 38.91	$ 34.81

Market value (2)	$ 2,826	$ 2,411	$ 2,876	$ 3,023	$ 2,708
Statements of Financial Position data (2)					
Total assets	$ 7,074	$ 6,710	$ 6,258	$ 6,123	$ 6,310
Property, plant and equipment – net	4,146	3,816	3,566	3,436	3,333
Total debt	2,576	2,541	2,255	2,161	2,137
Total equity	1,819	1,684	1,708	1,651	1,537
Cash flow data					
Net cash flow provided by operating activities	$ 592	$ 227	$ 377	$ 351	$ 80
Property, plant and equipment expenditures	476	372	259	253	267
Net (payments) and borrowings of short-term debt	(264)	286	52	6	188
Financial ratios (2)					
Debt	59 %	60 %	57 %	57 %	58 %
Equity	41 %	40 %	43 %	43 %	42 %
Total	100 %	100 %	100 %	100 %	100 %
Return on average equity	12.7 %	12.8 %	12.6 %	13.3 %	13.0 %

(1) These are non-GAAP measurements. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - AGL Resources-Results of Operations."

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

(3) Dividends declared per common share divided by market value per common share.

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

Overview

The distribution operations segment is the largest component of our business and is subject to regulation and oversight by agencies in each of the six 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 largest utility, the earnings of our regulated utilities can be affected by customer consumption patterns that are a function of weather conditions, price levels for natural gas and general economic conditions that may impact our customers' ability to pay for gas consumed. Various mechanisms exist that limit our exposure to weather changes within typical ranges in all of our jurisdictions.

Our retail energy operations segment, which consists of SouthStar, also is weather sensitive and uses a variety of hedging strategies, such as weather derivative instruments and other risk management tools, to mitigate potential weather impacts.
Our Sequent subsidiary within our wholesale services segment is temperature insensitive, but generally has greater opportunity to capture operating margin due to price volatility as a result of extreme weather. Our energy investments segment's primary activity is our natural gas storage business, which develops, acquires and operates high-deliverability salt-dome storage assets in the Gulf Coast region of the United States. While this business also can generate additional revenue during times of peak market demand for natural gas storage services, the majority of our storage services are covered under medium to long-term contracts at a fixed market rate.

Executive Summary

Regulatory strategy We continue to actively pursue a regulatory strategy that reduces the lag between our investments in infrastructure and the recovery of those investments through various rate mechanisms. Our regulatory planning includes rate design proposals that should provide stabilized revenues through decoupling, or separating the recovery of fixed costs for providing service from the volumes of customer throughput. Our rate cases also include proposals for energy-efficiency programs that should help customers lower the amount of gas used and conserve energy.

Capital projects We continue to focus aggressively on capital discipline and cost control, while moving ahead with projects and initiatives that we expect to have current and future benefits and provide an appropriate return on invested capital. In 2009, our infrastructure improvement programs were approved in Georgia and New Jersey. Additionally, the Magnolia pipeline project, completed in November 2009, allowing access to Elba Island LNG, should enable us to meet future demand for and diversify our supply of natural gas for Atlanta Gas Light customers. Our Hampton Roads Crossing pipeline project, with portions placed in service in December 2009 and the remainder in January 2010, provides additional infrastructure to accommodate growth to the Virginia Natural Gas distribution system. In addition, our Golden Triangle Storage project in Beaumont, Texas is on schedule and we expect the first cavern to be in operation in the second half of 2010.

Customer growth We continue to see challenging economic conditions in all of the areas we serve and, as a result, have experienced lower than expected customer growth in our distribution operations and retail energy operations segments throughout 2009, a trend we expect to continue through 2010.

For the year ended December 31, 2009, our distribution operations customer growth rate was (0.3)%, compared to 0.1% for 2008. The lower levels of customer growth are primarily a result of much slower growth in the residential housing markets throughout our service territories. This trend has been offset slightly by growth in the commercial customer segment in certain areas, primarily as a result of conversions to natural gas from other fuel sources as well as new product and service offerings.

We continue to use a variety of targeted marketing programs to attract new customers and to retain existing ones. 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 use analytical predictive models to identify and target customers who might consider switching from natural gas to other sources of energy in order to retain them as a customer.

We have seen a 4% decline in average customer count in Georgia at SouthStar for the year ended December 31, 2009, as compared to 2008. This decline reflects some of the same economic conditions that have affected our utility businesses, as well as a more competitive retail market for natural gas in Georgia.

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Natural gas price volatility Natural gas commodity prices have a significant impact on our customer rates and on our long-term competitive position against other energy sources. Over the last two years, daily Henry Hub spot market prices for natural gas in the United States has been extremely volatile and ranged between a high of $13.58 per Mcf in July 2008 to a low of $2.51 per Mcf in September 2009. Our natural gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. Although spot natural gas prices were as low as $2.51 per Mcf during 2009, the current forward price of natural gas continues to remain at much higher levels from $5.12 to $6.47 per Mcf over the next year. Our hedging strategies and physical natural gas supplies in storage enable us to reduce earnings risk exposure due to higher gas costs.

Capital market plan Our capital market plan over the next 12 to 18 months includes maintaining our total debt to total capitalization targets between 50% and 60%, the renewal of our $1 billion Credit Facility, the renewal of the letter of credit agreements which provide credit support for our variable-rate gas facility revenue bonds and refinancing of $300 million in 7.125% senior notes set to mature in January 2011.

We cannot predict whether renewing our Credit Facility or refinancing the senior notes would result in favorable terms or interest rates. Additionally, due to the significant changes in the credit markets, we expect that the costs of a renewed credit facility would increase and the duration to be less than the 5-year term under our existing Credit Facility. We have not yet determined whether we will seek to increase or decrease the size of the Credit Facility from its current $1 billion level.

Hedges

Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to reduce the risks associated with both weather-related seasonal fluctuations in market conditions and changing commodity prices. These economic hedges may not qualify, or are not designated for, hedge accounting treatment. As a result, our reported earnings for the wholesale services and retail energy operations segments 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 or our OCI for those derivative instruments that qualify and are designated as accounting hedges. The net losses on weather hedges during 2009 at retail energy operations were more than offset by corresponding increases in operating margin due to colder weather the hedges were designed to protect against.

Elizabethtown Gas utilizes certain financial derivatives in accordance with a directive from the New Jersey BPU to create a hedging program to hedge the impact of market fluctuations in natural gas prices. These derivative products are accounted for at fair value each reporting period. In accordance with regulatory requirements, realized gains and losses related to these financial derivatives are reflected in deferred natural gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset or liability, as appropriate, in our consolidated statements of financial position.

Seasonality

The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season, natural gas usage and operating revenues are generally higher because more customers are connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Occasionally in the summer, Sequent’s operating revenues are impacted due to peak usage by power generators in response to summer energy demands. Seasonality also affects the comparison of certain statements of financial position items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

Approximately 70% of these segments' operating revenues and 79% of these segments' EBIT for the year ended December 31, 2009 were generated during the first and fourth quarters of 2009, and are reflected in our consolidated statements of income for the quarters ended March 31, 2009 and December 31, 2009. Our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results can vary significantly from quarter to quarter as a result of seasonality.

Results of Operations

We generate nearly all our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date 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.

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In millions	2009	2008	2007
Residential	$ 1,091	$ 1,194	$ 1,143
Commercial	467	598	500
Transportation	378	459	401
Industrial	185	322	250
Other	196	227	200
Total operating revenues	$ 2,317	$ 2,800	$ 2,494

We evaluate segment performance using the measures of operating margin and EBIT, which include the effects of corporate expense allocations. Our operating margin and EBIT are not measures that are considered to be calculated in accordance with GAAP. Operating margin is a non-GAAP measure that is calculated as operating revenues minus cost of gas, which excludes operation and maintenance expense, depreciation and amortization, taxes other than income taxes, and the gain or loss on the sale of our assets; these items are included in our calculation of operating income as reflected in our consolidated statements of income. EBIT is also a non-GAAP measure that includes operating income, other income and expenses. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes, each of which we evaluate on a consolidated level.

We believe operating margin is a better indicator than operating revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally billed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of operating margin before overhead costs.

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

The table below sets forth a reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income, together with other consolidated financial information for the last three years.

In millions	2009	2008	2007
Operating revenues	$ 2,317	$ 2,800	$ 2,494
Cost of gas	1,142	1,654	1,369
Operating margin	1,175	1,146	1,125
Operating expenses	699	668	636
Operating income	476	478	489
Other income	9	6	4
EBIT	485	484	493
Interest expense	101	115	125
Earnings before income taxes	384	369	368
Income tax expense	135	132	127
Net income	249	237	241
	27	20	30

Less net income attributable to the noncontrolling interest			
Net income attributable to AGL Resources Inc.	$ 222	$ 217	$ 211

Over the last three years, on average, we have derived 67% of our operating segments' EBIT from our regulated natural gas distribution business whose rates are approved by state regulatory commissions. We derived our remaining operating segment's EBIT for the last three years principally from businesses that are complementary to our natural gas distribution business. These businesses include the sale of natural gas to retail customers, natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our regulated utility franchises.

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The following chart provides each operating segment's percentage contribution to the total EBIT for our operating segments for the last three years.

In 2009 our net income attributable to AGL Resources Inc. increased by $5 million from the prior year primarily due to decreased interest expense and increased EBIT from retail energy operations largely due to higher operating margin. This was partly offset by decreased EBIT at distribution operations, wholesale services and energy investments. The decrease in EBIT at distribution operations was primarily due to increased operating expenses offset by increased operating margin. The decrease in EBIT at wholesale services and energy investments was the result of decreased operating margins and increased operating expenses.

In 2008 our net income attributable to AGL Resources Inc. increased by $6 million from the prior year primarily due to decreased interest expenses and increased EBIT from wholesale services and energy investments largely due to higher operating margin offset by higher operating expenses. This was offset by decreased EBIT at distribution operations and retail energy operations due to lower operating margins at both operating segments and higher operating expenses at distribution operations.

Interest expense Our decreased interest expense over the last two years was primarily due to lower short-term interest rates partially offset by higher average debt. The following table provides additional detail on interest expense for the last three years and the primary items that affect year-over-year change.

In millions	2009	2008	2007
Interest expense	$ 101	$ 115	$ 125
Average debt outstanding (1)	$ 2,239	$ 2,156	$ 1,967
Average rate (2)	4.5 %	5.3 %	6.4 %

(1) Daily average of all outstanding debt.
(2) Excluding $3 million premium paid for early redemption of debt, average rate in 2007 would have been 6.2%.

The difficult economic conditions of the current recession have resulted in low U.S. Treasury yields and corresponding indexes on short-term borrowings. These factors have favorably impacted our earnings in 2009 and 2008 through reduced short-term rates that we paid on our commercial paper borrowings. For more information on the impact that interest rate fluctuations have on our variable-rate debt, see "Interest Rate Risk" in Item 7A, "Quantitative and Qualitative Disclosures About Market Risk."

Income tax expense Our income tax expense in 2009 increased by $3 million or 2% compared to 2008, and increased by $5 million or 4% in 2008 compared to 2007. These increases were primarily due to higher consolidated earnings. Our effective tax rate was 37.8% in 2009 and 2008 and was 37.6% in 2007.

As a result of our adoption of new authoritative guidance related to consolidations, income tax expense and our effective tax rate are determined from earnings before income taxes less net income attributable to the noncontrolling interest. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 8.

Operating metrics Selected weather, customer and volume metrics for 2009, 2008 and 2007, which we consider to be some of the key performance indicators for our operating segments, are presented in the following tables. We measure the effects of weather on our business through heating degree days. Generally, increased heating degree days result in greater demand for gas on our distribution systems. However, extended and unusually mild weather during the heating season can have a significant negative impact on demand for natural gas. Our customer metrics highlight the average number of customers to which we provide services. This number of customers can be impacted by natural gas prices, economic conditions and competition from alternative fuels. Volume metrics for distribution operations and retail energy operations present the effects of weather and our customers' demand for natural gas. Wholesale services' daily physical sales represent the daily average natural gas volumes sold to its customers.

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Weather Heating degree days (1)	Normal	Year ended December 31, 2009	2008	2007	2009 vs. 2008 colder (warmer)	2008 vs. 2007 colder (warmer)	2009 vs. normal colder (warmer)	2008 vs. normal colder (warmer)	2007 vs. normal colder (warmer)
Georgia	2,648	2,802	2,746	2,366	2 %	16 %	6 %	4 %	(11)%
New Jersey	4,692	4,751	4,646	4,777	2 %	(3)%	1 %	(1)%	2 %
Virginia	3,183	3,312	3,031	3,077	9 %	(1)%	4 %	(5)%	(3)%
Florida	513	548	416	326	32 %	28 %	7 %	(19)%	(36)%
Tennessee	3,036	3,154	3,179	2,722	(1)%	17 %	4 %	5 %	(10)%
Maryland	4,730	4,780	4,519	4,621	6 %	(2)%	1 %	(4)%	(2)%

	Normal	Quarter ended December 31, 2009	2008	2007	2009 vs. 2008 colder (warmer)	2008 vs. 2007 colder (warmer)	2009 vs. normal colder (warmer)	2008 vs. normal colder (warmer)	2007 vs. normal colder (warmer)
Georgia	1,048	1,181	1,092	877	8 %	25 %	13 %	4 %	(16)%
New Jersey	1,633	1,614	1,728	1,605	(7)%	8 %	(1)%	6 %	(2)%
Virginia	1,100	1,065	1,151	965	(7)%	19 %	(3)%	5 %	(12)%
Florida	164	158	201	45	(21)%	347 %	(4)%	23 %	(73)%
Tennessee	1,212	1,283	1,291	969	(1)%	33 %	6 %	7 %	(20)%
Maryland	1,678	1,662	1,691	1,558	(2)%	9 %	(1)%	1 %	(7)%

(1) Obtained from the National Oceanic and Atmospheric Administration, National Climatic Data Center. Normal represents the ten-year averages from January 2000 to December 2009.

Customers	Year ended December 31, 2009	2008	2007	2009 vs. 2008 % change	2008 vs. 2007 % change
Distribution Operations					
Average end-use customers (in thousands)					
Atlanta Gas Light	1,549	1,557	1,559	(0.5)%	(0.1)%
Elizabethtown Gas	273	273	272	-	0.4
Virginia Natural Gas	273	271	269	0.7	0.7
Florida City Gas	103	104	104	(1.0)	-
Chattanooga Gas	62	62	61	-	1.6
Elkton Gas	6	6	6	-	-
Total	2,266	2,273	2,271	(0.3)%	0.1 %
Operation and maintenance expenses per customer	$ 155	$ 145	$ 145	7 %	-
EBIT per customer	$ 144	$ 145	$ 149	(1)%	(3)%

Retail Energy Operations					
Average customers (in thousands)					
Georgia	504	526	540	(4)%	(3)%
Ohio and Florida (1)	103	122	41	(16)%	198 %
Total	607	648	581	(6)%	12 %
Market share in Georgia	33 %	34 %	35 %	(3)%	(3)%

Volumes In billion cubic feet (Bcf)	Year ended December 31, 2009	 2008	 2007	2009 vs. 2008 % change	2008 vs. 2007 % change
Distribution Operations					
Firm	218	219	211	-	4 %
Interruptible	98	104	108	(6)%	(4)
Total	316	323	319	(2)%	1 %
Retail Energy Operations					
Georgia firm	40	41	39	(2)%	5 %
Ohio and Florida	11	7	5	57 %	40 %
Wholesale Services					
Daily physical sales (Bcf / day)	2.96	2.60	2.35	14 %	11 %

(1) A portion of the Ohio customers represents customer equivalents, which are computed by the actual delivered volumes divided by the expected average customer usage.

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

In millions	Operating margin (1)	Operating expenses	EBIT (1)
2009			
Distribution operations	$ 836	$ 519	$ 326
Retail energy operations	181	76	105
Wholesale services	111	64	47
Energy investments	46	33	12
Corporate (2)	1	7	(5)
Consolidated	$ 1,175	$ 699	$ 485
2008			
Distribution operations	$ 818	$ 493	$ 329
Retail energy operations	149	73	77
Wholesale services	122	62	60
Energy investments	50	31	19
Corporate (2)	7	9	(1)
Consolidated	$ 1,146	$ 668	$ 484
2007			
Distribution operations	$ 820	$ 485	$ 338
Retail energy operations	188	75	113
Wholesale services	77	43	34
Energy investments	40	25	15
Corporate (2)	-	8	(7)
Consolidated	$ 1,125	$ 636	$ 493

(1) These are non-GAAP measurements. A reconciliation of operating margin to operating income and EBIT to earnings before income taxes and net income is contained in “Results of Operations” herein.

(2) Includes intercompany eliminations

Distribution Operations

In millions	2009	2008

EBIT – prior year	$ 329	$ 338
Operating margin		
Increased margins from gas storage carrying amounts at Atlanta Gas Light	8	-
Higher pipeline replacement program revenues at Atlanta Gas Light	6	6
Decreased customer growth and usage	-	(4)
Increased revenues from the Hampton Roads and Magnolia pipeline projects	2	-
Other	2	(4)
Increase (decrease) in operating margin	18	(2)
Operating expenses		
Increased (decreased) pension expenses	12	(5)
Increased payroll and incentive expenses	12	11
Increased depreciation expenses	6	6
(Decreased) increased bad debt expenses	(1)	5
(Decreased) increased fleet fuel costs	(3)	2
Decreased marketing costs	(2)	(5)
Other, overall net due to outside services, travel and entertainment and customer service expenses	2	(6)
Increase in operating expenses	26	8
Increase in other income, primarily from regulatory allowance for funds used during construction of Hampton Roads pipeline project	5	1
EBIT – current year	$ 326	$ 329

Retail Energy Operations

In millions	2009	2008
EBIT – prior year	$ 77	$ 113
Operating margin		
Change in LOCOM adjustment	18	(24)
Increased (decreased) contributions from the management and optimization of storage and transportation assets, and from retail price spreads	15	(9)
Change in retail pricing plan mix and decrease in average number of customers	(13)	(8)
Increased operating margins for Ohio, Florida and interruptible customers	5	2
Increased average customer usage and weather	4	1
Other	3	(1)
Increase (decrease) in operating margin	32	(39)
Operating expenses and other income		

(Decreased) increased bad debt expenses	(1)	3
Decreased depreciation expenses	-	(1)
Increased (decreased) marketing, compensation, customer care and other costs	4	(4)
Increase (decrease) in operating expenses	3	(2)
Other (expense) income	(1)	1
EBIT – current year	$ 105	$ 77

Wholesale Services

In millions	2009	2008
EBIT – prior year	$ 60	$ 34
Operating margin		
Change in storage hedge gains as a result of significant forward NYMEX natural gas price declines in 2008	(35)	24
Change in commercial activity	(19)	25
Increased gains on transportation hedges from the narrowing of transportation basis spreads and changes in park and loan hedges	27	11
Change in LOCOM adjustment, net of hedging recoveries	16	(15)
(Decrease) increase in operating margin	(11)	45
Operating expenses and other income		
Increased payroll and other operating costs due to continued expansion	-	13
(Decreased) increased depreciation expenses	(2)	1
Increased incentive compensation costs	4	6
Other	-	(1)
Increase in operating expenses	2	19
EBIT – current year	$ 47	$ 60

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The following table indicates the components of wholesale services' operating margin for 2009, 2008 and 2007.

In millions	2009	2008	2007
Commercial activity	$ 67	$ 86	$ 61
Gain on transportation hedges	43	7	5
Gain on storage hedges	1	36	12
Gain on park and loan hedges	-	9	-
Inventory LOCOM, net of hedging recoveries	-	(16)	(1)
Operating margin	$ 111	$ 122	$ 77

For more information on Sequent's expected operating revenues from its storage inventory in 2010 and discussion of commercial activity, see description of the inventory roll-out schedule in Item 1 "Business."

Energy Investments

In millions	2009	2008
EBIT – prior year	$ 19	$ 15
Operating margin		
(Decreased) increased revenues at AGL Networks largely due to changes in network expansion projects and increased customers in 2008	(1)	7
(Decreased) increased revenues at Jefferson Island	(2)	3
Other	(1)	-
(Decrease) increase in operating margin	(4)	10
Operating expenses and other loss		
Increased payroll and benefits, franchise fee and outside service costs due to expansion at AGL Networks	1	2
Increased legal and other expenses at Jefferson Island	1	3
Increased depreciation expenses	-	1
Increase in operating expenses	2	6
Increased other expenses	1	-
EBIT – current year	$ 12	$ 19

Liquidity and Capital Resources

Overview Our primary sources of liquidity are cash provided by operating activities, short-term borrowings under our commercial paper program (which is supported by our Credit Facility) and borrowings under subsidiary lines of credit. Our capital market strategy has continued to focus on maintaining a strong consolidated statement of financial position; ensuring ample cash resources and daily liquidity; accessing capital markets at favorable times as needed; managing critical business risks; and maintaining a balanced capital structure through the appropriate issuance of equity or long-term debt securities.

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval, or review by state and federal regulatory bodies including state public service commissions, the SEC and the FERC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation.

We believe the amounts available to us under our Credit Facility and the issuance of debt and equity securities together with cash provided by operating activities will continue to allow us to meet our needs for working capital, pension contributions, construction expenditures, anticipated debt redemptions, interest payments on debt obligations, dividend payments, common share repurchases and other cash needs through the next several years. Nevertheless, our ability to satisfy our working capital requirements and debt service obligations, or fund planned capital expenditures, will substantially depend upon our future operating performance (which will be affected by prevailing economic conditions), and financial, business and other factors, some of which are beyond our control.

We will continue to evaluate our need to increase available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by rating agencies and other factors. See Item 1A, "Risk Factors," for additional information on items that could impact our liquidity and capital resource requirements.

The following table provides a summary of our operating, investing and financing activities for the last three years.

In millions	2009	2008	2007
Net cash provided by (used in):			
Operating activities	$ 592	$ 227	$ 377
Investing activities	(476)	(372)	(253)
Financing activities	(106)	142	(122)
Net increase (decrease) in cash and cash equivalents	$ 10	$ (3)	$ 2

Cash Flow from Operating Activities We prepare our statement of cash flows using the indirect method. Under this method, we reconcile net income to cash flows from operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments during the period. These reconciling items include depreciation and amortization, changes in derivative financial instrument assets and liabilities, deferred income taxes and changes in the consolidated statements of financial position for working capital from the beginning to the end of the period.

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Our operations are seasonal in nature, with the business depending to a great extent on the first and fourth quarters of each year. As a result of this seasonality, our natural gas inventories are usually at their highest levels in November each year, and largely are drawn down in the heating season, providing a source of cash as this asset is used to satisfy winter sales demand. The injections in and price fluctuations of our natural gas inventories, which meet customer demand during the winter heating season, can cause significant variations in our cash flow from operations from period to period and are reflected in changes to our working capital.

Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our distribution operations, retail energy operations and wholesale services segments resulting from the impact of weather, the price of natural gas, the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries as our business has grown and prices for natural gas have increased. The increase or decrease in the price of natural gas directly impacts the cost of gas stored in inventory.

2009 compared to 2008 In 2009, our net cash flow provided from operating activities was $592 million, an increase of $365 million or 161% from 2008. The primary contributor to the recovery of working capital during 2009 was significantly lower natural gas commodity prices as compared to 2008. During 2008, the cost of natural gas increased significantly during the natural gas storage injection season. This resulted in a higher cost of inventories in 2008 as compared to 2009, and consequently higher customer bills and accounts receivable at the end of 2008. The higher receivable balances and inventory costs were billed to and /or collected from customers during 2009, which resulted in a $173 million increase in cash from the collection of our natural gas receivables and a $103 million increase in cash from our inventory withdrawals.

As a result of the lower natural gas prices during 2009, we used less cash as we refilled our natural gas inventories. The lower natural gas prices and associated inventory costs reduced customer bills at the end of 2009, allowing us to reduce our working capital needs. Also contributing to the higher operating cash flows was the return of cash collateral requirements posted during 2008 due to unrealized hedge losses resulting from the dramatic decline in natural gas prices during the second half of 2008 and into 2009. Cash collateral requirements decreased $200 million for our derivative financial instrument activities at Sequent and SouthStar due to the change in hedge values as forward NYMEX curve prices shifted downward in 2009.

2008 compared to 2007 In 2008, our net cash flow provided from operating activities was $227 million, a decrease of $150 million or 40% from 2007. This decrease was primarily a result of increased working capital requirements of $104 million, principally driven by increased cash used for inventory purchases which were impacted by rising natural gas prices during the first half of 2008.

Cash Flow from Investing Activities Our net cash used in investing activities consisted primarily of PP&E expenditures. The majority of our PP&E expenditures are within our distribution operations segment, which includes our investments in new construction and infrastructure improvements.

Our estimated PP&E expenditures in 2010 and actual PP&E expenditures in 2009, 2008 and 2007 are shown within the following categories and are presented in the table below.

- Base business – new construction and infrastructure improvements at our distribution operations segment
- Natural gas storage – salt-dome cavern expansions at Golden Triangle Storage and Jefferson Island
- Hampton Roads – Virginia Natural Gas' pipeline project, which connects its northern and southern systems
- Regulatory infrastructure programs – Programs that update or expand our distribution systems and liquefied natural gas facilities to improve system reliability and meet operational flexibility and growth. These programs include the pipeline replacement program and STRIDE at Atlanta Gas Light and Elizabethtown Gas' utility infrastructure enhancements program.

- Magnolia project – pipelines which diversify our sources of natural gas by connecting our Georgia service territory to the Elba Island LNG terminal
- Other – primarily includes information technology, building and leasehold improvements and AGL Networks' telecommunication expenditures

In millions	2007	2008	2009	2010 (1)
Base business	$ 135	$ 131	$ 132	$ 155
Natural gas storage	16	64	95	98
Hampton Roads	5	48	93	-
Regulatory infrastructure programs	41	70	76	155
Magnolia project	-	-	43	-
Other	62	59	37	61
Total	$ 259	$ 372	$ 476	$ 469

(1) Estimated

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In 2009, our PP&E expenditures were $104 million or 28% higher than in 2008. This was primarily due to $43 million expended for the completed Magnolia project, $45 million in increased spending for the completed Hampton Roads pipeline project and an increase in our natural gas storage project expenditures of $31 million as we continued construction of our Golden Triangle Storage facility. This was largely offset by decreased expenditures of $22 million for the other category, primarily on information technology and building and leasehold improvements.

In 2008, our PP&E expenditures were $113 million or 44% higher than in 2007. This was primarily due to an increase in our natural gas storage project expenditures of $48 million as we began construction of our Golden Triangle Storage facility, $43 million in increased expenditures for the Hampton Roads project and increased expenditures of $29 million for the pipeline replacement program at Atlanta Gas Light as we replaced larger-diameter pipe in more densely populated areas. This was offset by decreased expenditures of $7 million on our base business and other projects.

Our estimated expenditures for 2010 include discretionary spending for capital projects principally within the base business, natural gas storage and other categories. We continually evaluate whether to proceed with these projects, reviewing them in relation to factors including our authorized returns on rate base, other returns on invested capital for projects of a similar nature, capital structure and credit ratings, among others. We will make adjustments to these discretionary expenditures as necessary based upon these factors.

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

As of December 31, 2009, our variable-rate debt was $762 million or 30% of our total debt, compared to $1,026 million or 40% as of December 31, 2008. This decrease was principally due to lower natural gas prices during the 2009 inventory injection season and thus requiring lower working capital needs, as well as our issuance of $300 million in senior notes in 2009. As of December 31, 2009, our Credit Facility and commercial paper borrowings were $601 million or 22% lower than the same time last year, primarily a result of higher working capital requirements in 2008, driven by higher natural gas prices during the 2008 inventory injection season. For more information on our debt, see Note 6.

Our cash flows from financing activities reflect a net use of cash of $106 million in 2009 as compared to a net source of cash of $142 million in 2008. This change primarily reflects the repayment in 2009 of short-term debt outstanding at the end of 2008 coupled with our net borrowing last year to meet working capital needs due to higher natural gas prices.

Credit Ratings We strive to maintain or improve our credit ratings on our debt to manage our existing financing cost and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our statements of financial position leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any agreements that would require us to issue equity based on credit ratings or other trigger events. The following table summarizes our credit ratings as of December 31, 2009.

	S&P	Moody’s	Fitch
Corporate rating	A-		

Commercial paper	A-2	P-2	F2
Senior unsecured	BBB+	Baa1	A-
Ratings outlook	Stable	Stable	Stable

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating. We cannot ensure 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. 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 decrease.

Default Events Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to a maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions.

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Our Credit Facility has financial covenants that require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Our debt-to-equity calculation, as defined by our Credit Facility, was 57% at December 31, 2009 and 59% at December 31, 2008. These amounts are within our required and targeted ranges. The components of our capital structure, as calculated from our consolidated statements of financial position, as of the dates indicated, are provided in the following table.

In millions	December 31, 2009		December 31, 2008	
Short-term debt	$ 602	14 %	$ 866	20 %
Long-term debt	1,974	45	1,675	40
Total debt	2,576	59	2,541	60
Equity	1,819	41	1,684	40
Total capitalization	$ 4,395	100 %	$ 4,225	100 %

We currently comply with all existing debt provisions and covenants. We believe that accomplishing our capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs.

Short-term Debt Our short-term debt is composed of borrowings and payments under our Credit Facility and commercial paper program, lines of credit and payments of the current portion of our capital leases. Our short-term debt financing generally increases between June and December because our payments for natural gas and pipeline capacity are generally made to suppliers prior to the collection of accounts receivable from our customers. We typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

Our commercial paper borrowings are supported by our $1 billion Credit Facility, which expires in August 2011. Our supplemental $140 million Credit Facility expired in September 2009. We have the option to request an increase in the aggregate principal amount available for borrowing under the $1 billion Credit Facility to $1.25 billion on not more than three occasions during each calendar year.

We expect to begin the process of renewing our Credit Facility during 2010. Because of the current conditions in the credit markets, we are anticipating that the costs of a renewed Credit Facility will be significantly higher and that the term could be significantly shorter than the 5-year term of the current facility. These market conditions could also result in the need for us to increase the number of financial institution participants to provide a similar amount of financial commitments as our existing Credit Facility. As part of our renewal process we will consider whether the facility should increase or decrease from its current capacity of $1 billion.

SouthStar has a $75 million line of credit which is used for its working capital and general corporate needs. Additionally, Sequent has a $5 million line of credit that bears interest at the London interbank offered rate (LIBOR) rate plus 3.0%. Sequent’s line of credit is used solely for the posting of margin deposits for NYMEX transactions and is unconditionally guaranteed by us.

The lenders under our Credit Facility and lines of credit are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2009 as indicated in the following table. Investment grade, in the context of bond ratings, is the rating level above which institutional investors are authorized to invest (a bond judged likely enough to meet payment obligations that banks and pensions are allowed to invest in it).

Lender rating (S&P / Moody's)	Amount committed (in millions)	% of total
AAA / Aaa	$ -	-
AA / Aa	328	31 %
A / A	582	54 %
BBB / Baa	165	15 %
Total	$ 1,075	100 %

Based on current credit market conditions, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of our lenders' creditworthiness, we believe the risk of lender default is minimal.

As of December 31, 2009 we had no outstanding borrowings under our Credit Facility. As of December 31, 2008, we had $500 million of outstanding borrowings under the Credit Facility. We normally access the commercial paper markets to finance our working capital needs. However, during the third and fourth quarters of 2008, adverse developments in the global financial and credit markets made it more difficult for us to access the commercial paper market at reasonable rates. As a result, at times we relied instead upon our Credit Facility for our liquidity and capital resource needs. The credit markets improved in 2009, allowing us to resume our commercial paper borrowings.

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Increasing natural gas commodity prices can have a significant impact on our liquidity and working capital requirements. Based on current natural gas prices and our expected purchases during the upcoming injection season, a $1 increase per Mcf in natural gas prices could result in an additional $50 to $70 million of working capital requirements during the peak of the heating season based upon our current injection plan. This range is sensitive to the timing of storage injections and withdrawals, collateral requirements and our portfolio position.

Long-term Debt Our long-term debt matures more than one year from the statements of financial position date and consists of medium-term notes, senior notes, gas facility revenue bonds, and capital leases. The following represents our long-term debt activity over the last three years.

Gas Facility Revenue Bonds

- In June 2008, we refinanced $122 million of our gas facility revenue bonds, $47 million due October 2022, $20 million due October 2024 and $55 million due June 2032. There was no change to the maturity dates of these bonds. The $55 million bond had an interest rate that resets daily and the $47 million and $20 million bonds had a 35-day auction period where the interest rate adjusted every 35 days. Both the bonds with principal amounts of $47 million and $55 million now have interest rates that reset daily and the bond with a principal amount of $20 million has an interest rate that resets weekly. The interest rates at December 31, 2009, ranged from 0.2% to 0.4%.
- In September 2008, we refinanced $39 million of our gas facility revenue bonds due June 2026. The bonds had a 35-day auction period where the interest rate adjusted every 35 days now they have interest rates that reset daily. The maturity date of these bonds remains June 2026. The interest rate at December 31, 2009, was 0.2%.

Senior notes

- In December 2007, AGL Capital issued $125 million of 6.375% senior notes. The proceeds of the note issuances, equal to approximately $123 million, were used to pay down short-term indebtedness incurred under our commercial paper program.
- In August 2009, AGL Capital issued $300 million of 10-year senior notes at an interest rate of 5.25%. The net proceeds from the offering were approximately $297 million. We used the net proceeds from the sale of the senior notes to repay a portion of our short-term debt.

Notes payable to Trusts

- In July 2007, we used the proceeds from the sale of commercial paper to pay AGL Capital Trust I the $75 million principal amount of 8.17% junior subordinated debentures plus a $3 million premium for early redemption of the junior subordinated debentures, and to pay a $2 million note representing our common securities interest in AGL Capital Trust I.

Medium-term notes

- In January 2007, we used proceeds from the sale of commercial paper to redeem $11 million of 7% medium-term notes previously scheduled to mature in January 2015.

Noncontrolling Interest A cash distribution for SouthStar's dividend distributions to Piedmont of $20 million in 2009, $30 million in 2008 and $23 million in 2007 was recorded in our consolidated statement of cash flows as a financing activity.

Dividends on Common Stock Our common stock dividend payments were $127 million in 2009, $124 million in 2008, and $123 million in 2007. The increases were generally the result of annual dividend increases of $0.04 per share for each of the last two years. Our average dividend yield over the last three years was 4.8%, which is slightly higher than the average 4.0% dividend yield of our peer companies. Our dividend payout ratio was 60% in 2009, 59% in 2008 and 54% in 2007. We expect that our dividend payout ratio will remain consistent with the dividend payout ratios of our peer companies, which is currently an average of 63%. For information about restrictions on our ability to pay dividends on our common stock, see Note 1 "Accounting Policies and Methods of Application."

Treasury Shares In February 2006, our Board of Directors authorized a plan to purchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of common shares that we will purchase, and we can terminate or limit the program at any time.

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For the years ended December 31, 2009 and 2008, we did not purchase shares of our common stock. During the same period in 2007, we purchased approximately 2 million shares of our common stock at a weighted average cost of $39.56 per common share and an aggregate cost of $80 million. We currently anticipate holding the purchased shares as treasury shares. For more information on our common share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration In August 2007, we filed a shelf registration with the SEC, which expires in August 2010. The debt securities and related guarantees will be issued by AGL Capital under an indenture dated as of February 20, 2001, as supplemented and modified, as necessary, among AGL Capital, AGL Resources and The Bank of New York Trust Company, N.A., as trustee. The indenture provides for the issuance from time to time of debt securities in an unlimited dollar amount and an unlimited number of series, subject to our Credit Facility financial covenants related to total debt to total capitalization. The debt securities will be guaranteed by AGL Resources. In 2010, we expect to file a new shelf registration statement with the SEC that would expire in 2013.

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material effect on liquidity or the availability of requirements for capital resources. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements.

These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. As we do for other subsidiaries, AGL Resources provides guarantees to certain gas suppliers for SouthStar in support of payment obligations. The following table illustrates our expected future contractual obligation payments such as debt and lease agreements, and commitments and contingencies as of December 31, 2009.

In millions	Total	2010	2011 & 2012	2013 & 2014	2015 & thereafter
Recorded contractual obligations:					
Long-term debt	$ 1,974	$ -	$ 318	$ 225	$ 1,431
Short-term debt	602	602	-	-	-
Pipeline replacement program costs (1)	210	55	111	44	-
Environmental remediation liabilities (1)	144	25	54	38	27
Total	$ 2,930	$ 682	$ 483	$ 307	$ 1,458
Unrecorded contractual obligations and commitments (2):					
Pipeline charges, storage capacity and gas supply (3)	$ 2,049	$ 510	$ 712	$ 354	$ 473
Interest charges (4)	1,014	109	176	156	573
Operating leases	115	28	40	14	33
Asset management agreements (5)	37	23	14	-	-
Pension contributions	21	21	-	-	-

Standby letters of credit, performance / surety bonds	19	18	1	-	-
Total	$ 3,255	$ 709	$ 943	$ 524	$ 1,079

(1) Includes charges recoverable through rate rider mechanisms.

(2) In accordance with GAAP, these items are not reflected in our consolidated statements of financial position.

(3) Charges recoverable through a natural gas cost recovery mechanism or alternatively billed to Marketers, and includes demand charges associated with Sequent. The gas supply amount includes SouthStar gas commodity purchase commitments of 16 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2009, and is valued at $97 million.

(4) Floating rate debt is based on the interest rate as of December 31, 2009, and the maturity of the underlying debt instrument. As of December 31, 2009, we have $41 million of accrued interest on our consolidated statements of financial position that will be paid in 2010.

(5) Represent fixed-fee minimum payments for Sequent's asset management agreements.

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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. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein. We expect to fund these obligations with cash flow from operating and financing activities.

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 include the nature of the guarantee 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 Postretirement Obligations. Generally, our funding policy is to contribute annually an amount that will at least equal the minimum amount required to comply with the Pension Protection Act. Additionally, we calculate any required pension contributions using the projected unit credit cost method. However, additional voluntary contributions are made from time to time as considered necessary. 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 postretirement costs we are responsible for under the terms of our plan and minimum funding required by state regulatory commissions.

The state regulatory commissions have phase-ins that defer a portion of the postretirement benefit expense for future recovery. We recorded a regulatory asset for these future recoveries of $10 million as of December 31, 2009 and $11 million as of December 31, 2008. In addition, we recorded a regulatory liability of $5 million as of December 31, 2009 and $5 million as of December 31, 2008 for our expected expenses under the AGL Postretirement Plan. See Note 3 “Employee Benefit Plans,” for additional information about our pension and postretirement plans.

In 2009, we contributed $24 million to our qualified pension plans. In 2008, we did not make a contribution, as one was not required. Based on the current funding status of the plans, we would be required to make a minimum contribution to the plans of approximately $21 million in 2010. We are planning to make additional contributions in 2010 up to $17 million, for a total of up to $38 million, in order to preserve the current level of benefits under the plans and in accordance with the funding requirements of the Pension Protection Act.

Critical Accounting Estimates

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Our actual results may differ from our estimates. Each of the following critical accounting estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements.

Pipeline Replacement Program Liabilities Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Georgia Commission staff) to undertake a pipeline replacement program that would replace all bare steel and cast iron pipe in its system. Approximately 31 miles of cast iron and 303 miles of bare steel pipe still require replacement. If Atlanta Gas Light does not perform in accordance with the initial and amended pipeline replacement program stipulation, it can be assessed certain nonperformance penalties. However to date, Atlanta Gas Light is in full compliance.

The stipulation also provides for recovery of all prudent costs incurred under the program, which Atlanta Gas Light has recorded as a regulatory asset. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through rate riders
- the future expected costs to be recovered through rate riders

The determination of future expected costs associated with our pipeline replacement program involves judgment. Factors that must be considered in estimating the future expected costs are projected capital expenditure spending, including labor and material costs, and the remaining infrastructure footage to be replaced for the remaining years of the program. We recorded a long-term liability of $155 million as of December 31, 2009 and $140 million as of December 31, 2008, which represented engineering estimates for remaining capital expenditure costs in the pipeline replacement program. As of December 31, 2009, we had recorded a current liability of $55 million, representing expected pipeline replacement program expenditures for the next 12 months. We report these estimates on an undiscounted basis. If Atlanta Gas Light's pipeline replacement program expenditures, subject to future recovery, were $10 million higher or lower its incremental expected annual revenues would have changed by approximately $1 million.

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Environmental Remediation Liabilities We historically reported estimates of future remediation costs based on probabilistic models of potential costs. We report these estimates on an undiscounted basis. As we continue to conduct the actual remediation and enter into cleanup contracts, we are increasingly able to provide conventional engineering estimates of the likely costs of many elements of the remediation program. These estimates contain various engineering uncertainties, and we continuously attempt to refine and update these engineering estimates. The following table provides more information on our former operating sites:

In millions	Cost estimate range	Amount recorded	Expected costs over next twelve months
Georgia and Florida	$ 64 - $113	$ 64	$ 13
New Jersey	69 - 134	69	11
North Carolina	11 - 16	11	1
Total	$ 144 - $263	$ 144	$ 25

We have confirmed 13 former operating sites in Georgia and Florida where Atlanta Gas Light owned or operated all or part of these sites. One additional former MGP site has been recently identified adjacent to an existing MGP remediation site. Precise engineering soil and groundwater clean up estimates are not available and considerable variability exists with this potential new site. As of December 31, 2009, the soil and sediment remediation program was substantially complete for all Georgia sites, except for a few remaining areas of recently discovered impact, although groundwater cleanup continues. Investigation is concluded for one phase of the Orlando, Florida site; however, the Environmental Protection Agency has not approved the clean up plans. For elements of the Georgia and Florida sites where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

Additionally, we have identified six former operating sites in New Jersey where Elizabethtown Gas owned or operated all or part of these sites. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. We have also identified a site in North Carolina, which is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. There are no cost recovery mechanisms for the environmental remediation of this site.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. Atlanta Gas Light's estimate does not include other potential expenses, such as unasserted property damage, personal injury or natural resource damage claims, unbudgeted legal expenses, or other costs for which it may be held liable but with respect to which the amount cannot be reasonably forecast. Atlanta Gas Light's recovery of environmental remediation costs is subject to review by the Georgia Commission, which may seek to disallow the recovery of some expenses.

In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. The New Jersey BPU has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. Elizabethtown Gas has been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery. As of December 31, 2009, the variation between the amounts of the environmental remediation cost liability recorded in the consolidated statements of financial position and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own remediation sites located outside of New Jersey. One site, in Elizabeth City, North Carolina, is subject to an order by the North Carolina Department of Environment and Natural Resources. There is one other site in North Carolina where investigation and remediation is possible, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers (except for the Elizabeth City, North Carolina site), former owners and operators and insurance carriers. While we have been successful in recovering a portion of these remediation costs from our insurance carriers, we are not able to express a belief as to the success of additional recovery efforts. We are working with the regulatory agencies to manage our remediation costs so as to mitigate the impact of such costs on both ratepayers and shareholders.

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Derivatives and Hedging Activities The authoritative guidance related to derivatives and hedging established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the statements of financial position as either an asset or liability measured at its fair value. However, if the derivative transaction qualifies for and is designated as a normal purchase and sale, it is exempted from the fair value accounting treatment of this guidance, and is accounted for using traditional accrual accounting.

The guidance requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. If the derivatives meet those criteria, the guidance allows a derivative's gains and losses to offset related results on the hedged item in the income statement in the case of a fair value hedge, or to record the gains and losses in OCI until the hedged transaction occurs in the case of a cash flow hedge. Additionally, the guidance requires that a company formally designate a derivative as a hedge as well as document and assess the effectiveness of derivatives associated with transactions that receive hedge accounting treatment. The guidance applies to gas commodity contracts executed by Sequent and SouthStar. The guidance also applies to gas commodity contracts executed by Elizabethtown Gas under a New Jersey BPU authorized hedging program that requires gains and losses on these derivatives are reflected in purchased gas costs and ultimately billed to customers. Our derivative and hedging activities are described in further detail in Note 2 and Item 1 "Business."

Commodity-related Derivative Instruments We are exposed to risks associated with changes in the market price of natural gas. Through Sequent and SouthStar, we use derivative financial instruments to reduce our exposure impact to our results of operations due to the risk of changes in the price of natural gas.

Sequent recognizes the change in value of a derivative financial instrument as an unrealized gain or loss in revenues in the period when the market value of the instrument changes. Sequent recognizes cash inflows and outflows associated with the settlement of its risk management activities in operating cash flows, and reports these settlements as receivables and payables in the statements of financial position separately from the risk management activities reported as energy marketing receivables and trade payables.

We attempt to mitigate substantially all of our commodity price risk associated with Sequent's natural gas storage portfolio and lock in the economic margin at the time we enter into purchase transactions for our stored natural gas. We purchase natural gas for storage when the current market price we pay plus storage costs is less than the market price we could receive in the future. We lock in the economic margin by selling NYMEX futures contracts or other OTC derivatives in the forward months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to lock in the operating revenues we will ultimately realize when the stored natural gas is actually sold. These contracts meet the definition of a derivative under the authoritative guidance related to derivatives and hedging.

The purchase, storage and sale of natural gas are accounted for differently from the derivatives we use to mitigate the commodity price risk associated with our storage portfolio. That difference in accounting can result in volatility in our reported operating margin, even though the economic margin is essentially unchanged from the date we entered into the transactions. We do not currently use hedge accounting under the authoritative guidance to account for this activity.

Natural gas that we purchase and inject into storage is accounted for at the lower of weighted average cost or market value. Under current accounting guidance, we recognize a loss in any period when the market price for natural gas is lower than the carrying amount of our purchased natural gas inventory. Costs to store the natural gas are recognized in the period the costs are incurred. We recognize revenues and cost of natural gas sold in our statement of consolidated income in the period we sell gas and it is delivered out of the storage facility.

The derivatives we use to mitigate commodity price risk and substantially lock in the operating margin upon the sale of stored natural gas are accounted for at fair value and marked to market each period, with changes in fair value recognized as unrealized gains or losses in the period of change. This difference in accounting - the lower of weighted average cost or market basis for our storage inventory versus the fair value accounting for the derivatives used to mitigate commodity price risk - can and does result in volatility in our reported earnings.

Over time, gains or losses on the sale of storage inventory will be substantially offset by losses or gains on the derivatives, resulting in realization of the economic profit margin we expected when we entered into the transactions. This accounting difference causes Sequent’s earnings on its storage positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged.

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SouthStar also uses derivative instruments to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to minimize volatility in wholesale commodity natural gas prices. A portion of SouthStar's derivative transactions are designated as cash flow hedges under authoritative guidance related to derivatives and hedging. Derivative gains or losses arising from cash flow hedges are recorded in OCI and are reclassified into earnings in the same period the underlying hedged item is reflected in the income statement. As of December 31, 2009, the ending balance in OCI for derivative transactions designated as cash flow hedges under the guidance was a loss of $4 million, net of noncontrolling interest and taxes. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item, is recorded into earnings in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. SouthStar's remaining derivative instruments are not designated as hedges under the guidance. Therefore, changes in their fair value are recorded in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to stabilize operating margins in the event of warmer-than-normal and colder-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under the authoritative guidance related to financial instruments. Changes in the intrinsic value of these derivatives are recorded in earnings in the period of change. The weather derivative contracts contain strike amount provisions based on cumulative heating degree days for the covered periods. In 2009, 2008 and 2007, SouthStar entered into weather derivatives (swaps and options) for the respective winter heating seasons, primarily from November through March. As of December 31, 2009, SouthStar recorded a current asset of $2 million for this hedging activity.

Contingencies Our accounting policies for contingencies cover a variety of business activities, including contingencies for potentially uncollectible receivables, rate matters, 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 in accordance with authoritative guidance related to contingencies. We base our estimates for these liabilities on currently available facts and our estimates of the ultimate outcome or resolution of the liability in the future. Actual results may differ from estimates, and estimates can be, and often are, revised either negatively or positively, depending on actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Pension and Other Postretirement Plans Our pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We annually review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities. The assumed discount rate and the expected return on plan assets are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the expected return on assets, the assumed health care cost trend rate and the assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement costs. When establishing our discount rate, we consider a variety of factors in determining and selecting our assumptions for the discount rate. With the assistance of our actuaries, we consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate, other high-grade bond indices and a single equivalent discount rate derived utilizing the forecasted future cash flows in each year to the appropriate spot rates based on high quality (AA or better) corporate bonds.

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

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During 2009, we recorded net periodic benefit costs of $12 million related to our defined pension and postretirement benefit costs. We estimate that in 2010, we will record net periodic pension and other postretirement benefit costs in the range of $15 million to $17 million, a $3 million to $5 million increase compared to 2009. In determining our estimated expenses for 2010, our actuarial consultant assumed an 8.75% expected return on plan assets and a discount rate of 6% for the AGL Retirement Plan and 5.75% for the NUI Retirement Plan and for our postretirement plan. The actuarial assumptions used 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. These differences may result in a significant impact on the amount of pension and postretirement expense recorded in future periods. The following table illustrates the effect of changing the critical actuarial assumptions for our pension and postretirement plans, as discussed previously, while holding all other assumptions constant.

		In millions	
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1 %	$ - / -	$ (4) / 4
Discount rate	+/- 1 %	(58) / 64	(5) / 5

Effective on July 1, 2009, all post-65 health coverage except for the retiree health care reimbursement account and opt-out benefits was eliminated. There were no changes to the life insurance plan. Effective January 1, 2010, enhancements were made to the pre-65 medical coverage by removing the current cap on the expected costs and implementation of a new cap determined by the new retiree premium schedule based on salary level and years of service. Consequently, a one-percentage-point increase or decrease in the assumed health care trend rate does not materially affect the periodic benefit cost or our accumulated projected benefit obligation for our postretirement plans. Our assumed rate of retirement is estimated based upon an annual review of participant census information as of the measurement date.

At December 31, 2009, our pension and postretirement liability decreased by approximately $48 million, primarily resulting from an after-tax gain to OCI of $17 million ($28 million before tax), 2009 contributions of $24 million and $8 million in benefit payments that we funded offset by $12 million in net pension and postretirement benefit costs we recorded in 2009. These changes reflect our funding contributions to the plan, benefit payments out of the plans, and updated valuations for the projected benefit obligation (PBO) and plan assets.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded PBO and accumulated postretirement benefit obligation, as the primary factors that drive the value of our unfunded accumulated benefit obligation are the assumed discount rate and the actual return on plan assets. Additionally, for our largest pension plan equity market performance has a significant effect on 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 moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed 10% of the greater of the PBO or the MRVPA. If necessary, the excess is amortized over the average remaining service period of active employees.

See "Note 3, Employee Benefit Plans," for additional information on our pension and postretirement plans, which includes our investment policies and strategies, target allocation ranges and weighted average asset allocations for 2009 and 2008.

Income Taxes We account for income taxes in accordance with authoritative guidance related to income taxes which require 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 if it is more likely than not that some portion or all of the deferred tax asset will not be realized. As of December 31, 2008 and December 31, 2009, we did not have a liability for unrecognized tax benefits. As a result of our adoption of new authoritative guidance related to consolidations, income tax expense and our effective tax rate are determined from earnings before income tax less net income attributable to the noncontrolling interest. For more information on our adoption of this guidance, see Note 5.

Our net long-term deferred tax liability totaled $695 million at December 31, 2009 (see Note 8 “Income Taxes”). This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our income tax returns. 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. We had a $3 million valuation allowance on $79 million of deferred tax assets as of December 31, 2009, reflecting the expectation that most of these assets will be realized. In addition, we operate within multiple taxing jurisdictions and we are subject to audit 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.

Accounting Developments

Variable Interest Entity

In June 2009, the FASB issued authoritative guidance, which amended the guidance related to transfers and servicing. This guidance requires improved disclosures about transfers of financial assets and removes the exception from applying the guidance related to consolidations specifically for variable interest entities (VIE) to qualifying special purpose entities. This amendment will be effective for us on January 1, 2010 and it will have no effect on our consolidated results of operations, cash flows or financial position.

In June 2009, the FASB issued additional consolidation guidance for VIE. This authoritative guidance requires us to assess the determination of the primary beneficiary of a VIE based on whether we have the power to direct matters that most significantly impact the activities of the VIE, and has the obligation to absorb losses or the right to receive benefits of the VIE. In addition, the guidance requires ongoing reassessments of whether we are the primary beneficiary of a VIE. The guidance will be effective for us beginning January 1, 2010 and it will have no effect on our consolidated results of operations, cash flows or financial position. Our VIE is described in further detail in Note 5.

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 is defined as the potential loss that we may incur as a result of changes in the fair value of natural gas. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services.

Our Risk Management Committee (RMC) is responsible for establishing the overall risk management policies and monitoring compliance with, and adherence to, the terms within these policies, including approval and authorization levels and delegation of these levels. Our RMC consists of members of senior management who monitor open natural gas price risk positions and other types of risk, corporate exposures, credit exposures and overall results of our risk management activities. It is chaired by our chief risk officer, who is responsible for ensuring that appropriate reporting mechanisms exist for the RMC to perform its monitoring functions. Our risk management activities and related accounting treatments are described in further detail in Note 2.

Natural Gas Price Risk

Retail Energy Operations SouthStar's use of derivative instruments is governed by a risk management policy, approved and monitored by its Finance and Risk Management Committee, which prohibits the use of derivatives for speculative purposes.

Energy Marketing and Risk Management Activities SouthStar routinely utilizes various types of derivative financial instruments to mitigate certain natural gas price and weather risk inherent in the natural gas industry. This includes the active management of storage positions through a variety of hedging transactions for the purpose of managing exposures arising from changing natural gas prices. SouthStar uses these hedging instruments to lock in economic margins (as spreads between wholesale and retail natural gas prices widen between periods) and thereby minimize its exposure to declining operating margins.

We have designated a portion of SouthStar's derivative transactions as cash flow hedges in accordance with authoritative guidance related to derivatives and hedging. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings as cost of gas in our consolidated statement of income in the same period as the underlying hedged transaction occurs and is recorded in earnings. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our consolidated statement of income in the period in which the ineffectiveness occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under the guidance and, accordingly, we record changes in their fair value in earnings as cost of gas in our consolidated statements of income in the period of change.

SouthStar recorded a net unrealized gain related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $20 million during 2009, unrealized losses of $27 million during 2008 and $7 million during 2007. The following tables illustrate the change in the net fair value of the derivative financial instruments during 2009, 2008 and 2007 and provide details of the net fair value of derivative financial instruments outstanding as of December 31, 2009, 2008 and 2007.

In millions	2009	2008	2007
Net fair value of derivative financial instruments outstanding at beginning of period	$ (17)	$ 10	$ 17
	19	(10)	(17)

Derivative financial instruments realized or otherwise settled during period			
Change in net fair value of derivative financial instruments	1	(17)	10
Net fair value of derivative financial instruments outstanding at end of period (1)	3	(17)	10
Netting of cash collateral	18	31	3
Cash collateral and net fair value of derivative financial instruments outstanding at end of period (1)	$ 21	$ 14	$ 13

(1) Net fair value of derivative financial instruments outstanding includes $2 million premium and associated intrinsic value at December 31, 2009, $4 million at December 31, 2008 and $5 million at December 31, 2007 associated with weather derivatives.

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The sources of SouthStar's net fair value of its natural gas-related derivative financial instruments at December 31, 2009, are as follows.

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through 2010 (3)	$ 1	$ 2

(1) Valued using NYMEX futures prices.

(2) Values primarily related to weather derivative transactions that are valued on an intrinsic basis in accordance with authoritative guidance related to financial instruments as based on heating degree days. Additionally, includes values associated with basis transactions that represent the commodity from 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.

SouthStar routinely utilizes various types of financial and other instruments to mitigate certain commodity 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. The following tables include the fair values and average values of SouthStar's derivative instruments as of the dates indicated. SouthStar bases the average values on monthly averages for the 12 months ended December 31, 2009 and 2008.

In millions	Derivative financial instruments average fair values at December 31, 2009 (1)	2008 (1)
Asset	$ 13	$ 17
Liability	19	12

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at December 31, 2009	2008	2007
Asset	$ 21	$ 16	$ 13
Liability	-	2	-

Value-at-risk A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means that over the holding period, an actual loss in portfolio value is not expected to exceed the calculated VaR more than 5%

of the time. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as price distribution, price volatility, confidence interval and holding period. Our VaR may not be comparable to a similarly titled measure of another company because, although VaR is a common metric in the energy industry, there is no established industry standard for calculating VaR or for the assumptions underlying such calculations. SouthStar's portfolio of positions for 2009, 2008 and 2007, had annual average 1-day holding period VaRs of less than $100,000, and its high, low and period end 1-day holding period VaR were immaterial.

Wholesale Services Sequent routinely uses various types of derivative financial instruments to mitigate certain natural gas price 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 financial swap agreements.

Energy Marketing and Risk Management Activities We account for derivative transactions in connection with Sequent's energy marketing activities on a fair value basis in accordance with authoritative guidance related to derivatives and hedging. We record derivative energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains or losses from changes in fair value reflected in our earnings in the period of change.

Sequent's energy-trading contracts are recorded on an accrual basis and its derivatives are recorded at fair value under authoritative guidance related to derivatives and hedging.

Sequent experienced a $36 million increase in the net fair value of its outstanding contracts during 2009 and $25 million during 2008 and a $62 million decrease in the net fair value of its outstanding contracts during 2007, due to changes in the fair value of derivative financial instruments utilized in its energy marketing and risk management activities and contract settlements and new business contracts acquired in 2009. The following tables illustrate the change in the net fair value of Sequent's derivative financial instruments during 2009, 2008 and 2007 and provide details of the net fair value of contracts outstanding as of December 31, 2009, 2008 and 2007.

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In millions	2009	2008	2007
Net fair value of derivative financial instruments outstanding at beginning of period	$ 82	$ 57	$ 119
Derivative financial instruments realized or otherwise settled during period	(73)	(49)	(102)
Net fair value of derivative financial instruments acquired during period	50	-	-
Change in net fair value of derivative financial instruments	59	74	40
Net fair value of derivative financial instruments outstanding at end of period	118	82	57
Netting of cash collateral	39	97	(9)
Cash collateral and net fair value of derivative financial instruments outstanding at end of period	$ 157	$ 179	$ 48

The sources of Sequent's net fair value at December 31, 2009, are as follows.

In millions	Prices actively quoted (Level 1) (1)	Significant other observable inputs (Level 2) (2)
Mature through		
2010	$ (4)	$ 82
2011 - 2012	2	25
2013 - 2015	1	12
Total derivative financial instruments (3)	$ (1)	$ 119

(1) Valued using NYMEX futures prices.

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

(3) Excludes cash collateral amounts.

The following tables include the cash collateral fair values and average values of Sequent's energy marketing and risk management assets and liabilities as of December 31, 2009 and 2008. Sequent bases the average values on monthly averages for the 12 months ended December 31, 2009 and 2008.

	Derivative financial instruments average fair values at December 31,	
In millions	2009 (1)	2008 (1)
Asset	$ 170	$ 96
Liability	68	45

(1) Excludes cash collateral amounts.

In millions	Derivative financial instruments fair values netted with cash collateral at December 31, 2009	2008	2007
Asset	$ 208	$ 206	$ 61
Liability	51	27	13

Value-at-risk Sequent's 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 Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures markets, its open exposure is generally immaterial, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where its total buy volume is close to its sell volume, with minimal open natural gas price risk. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the 12 months ended December 31, 2009, 2008 and 2007 had the following VaRs.

In millions	2009	2008	2007
Period end	$ 2.4	$ 2.5	$ 1.2
12-month average	1.8	1.8	1.3
High	3.3	3.1	2.3
Low	0.7	0.8	0.7

Energy Investments In 2009, Golden Triangle Storage began using derivative financial instruments to reduce its exposure during the construction of the storage caverns to the risk of changes with the price of natural gas that will be purchased in future periods for pad gas, which includes volumes of non-working natural gas used to maintain the operational integrity of the caverns. As of December 31, 2009, Golden Triangle Storage had locked-in the price of approximately 68% of the required pad gas for the first storage cavern or 2 Bcf and the associated fair value of the derivative financial instruments was immaterial.

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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 $762 million of variable-rate debt, which includes $601 million of our variable-rate short-term debt and $161 million of variable-rate gas facility revenue bonds outstanding at December 31, 2009, a 100 basis point change in market interest rates from 0.4% to 1.4% would have resulted in an increase in pretax interest expense of $8 million on an annualized basis.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills nine certificated and active Marketers and one regulated natural gas provider responsible for offering natural gas to low-income customers and customers unable to get natural gas service from other Marketers in Georgia for its services. The credit risk exposure to Marketers varies with the time of the year, with exposure at its lowest in the nonpeak summer months and highest in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of the natural gas commodity. The provisions of Atlanta Gas Light's tariff allow Atlanta Gas Light to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from Atlanta Gas Light. For 2009, the four largest Marketers based on customer count, which includes SouthStar, accounted for approximately 31% of our consolidated operating margin and 44% of distribution operations' operating margin.

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

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

Retail Energy Operations SouthStar obtains credit scores for its firm residential and small commercial customers using a national credit reporting agency, enrolling only those customers that meet or exceed SouthStar's credit threshold.

SouthStar considers potential interruptible and large commercial customers based on a review of publicly available financial statements and review of commercially available credit reports. Prior to entering into a physical transaction, SouthStar also assigns 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 Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, as well as the quality of pledged collateral. Sequent also utilizes master netting agreements whenever possible to mitigate exposure to counterparty credit risk. When Sequent 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 and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions. Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral provided the master netting and cash collateral agreements include such provisions.

Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. Sequent conducts credit evaluations and obtains appropriate internal approvals for its 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, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for transaction counterparties that do not have investment grade ratings.

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Sequent, which provides services to retail marketers and utility and industrial customers, also has a concentration of credit risk as measured by its 30-day receivable exposure plus forward exposure. As of December 31, 2009, Sequent's top 20 counterparties represented approximately 58% of the total counterparty exposure of $534 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2009, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from 9 to 1, with 9 being equivalent to AAA/Aaa by S&P and Moody's and 1 being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty. To arrive at the weighted average credit rating, each counterparty is assigned an internal ratio, which is multiplied by their credit exposure and summed for all counterparties. The sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. There were no credit defaults with Sequent's counterparties. The following table shows Sequent's third-party natural gas contracts receivable and payable positions.

	As of Dec. 31, Gross receivables	
In millions	2009	2008
Netting agreements in place:		
Counterparty is investment grade	$ 483	$ 398
Counterparty is non-investment grade	12	15
Counterparty has no external rating	106	129
No netting agreements in place:		
Counterparty is investment grade	14	7
Counterparty is non-investment grade	-	-
Amount recorded on statements of financial position	$ 615	$ 549

	As of Dec. 31, Gross payables	
In millions	2009	2008
Netting agreements in place:		
Counterparty is investment grade	$ 277	$ 266
Counterparty is non-investment grade	34	41

Counterparty has no external rating	207	228
No netting agreements in place:		
Counterparty is investment grade	6	4
Counterparty is non-investment grade	-	-
Amount recorded on statements of financial position	$ 524	$ 539

Sequent has 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, Sequent would need to post collateral to continue transacting business with some of its counterparties. If such collateral were not posted, Sequent's 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 between Sequent and its counterparties would have totaled $25 million at December 31, 2009, which would not have a material impact to our consolidated results of operations, cash flows or financial condition.

Glossary of Key Terms

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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control - Integrated Framework 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 Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Atlanta, Georgia
February 4, 2010

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

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

Based on our evaluation under the framework in Internal Control – Integrated Framework issued by COSO, our management concluded that our internal control over financial reporting was effective as of December 31, 2009, in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

February 4, 2010

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

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

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AGL Resources Inc.
Consolidated Statements of Financial Position - Assets

	As of December 31,	
In millions	2009	2008
Current assets		
Cash and cash equivalents (Note 1)	$ 26	$ 16
Receivables (Note 1)		
Energy marketing receivables	615	549
Gas	178	264
Unbilled revenues	155	181
Other	29	27
Less allowance for uncollectible accounts	14	16
Total receivables	963	1,005
Inventories (Note 1)		
Natural gas stored underground	649	629
Other	23	34
Total inventories	672	663
Derivative financial instruments – current portion (Note 1 and Note 2)	188	207
Unrecovered regulatory infrastructure program costs – current portion (Note 1)	43	41
Unrecovered environmental remediation costs – current portion (Note 1 and Note 7)	11	18
Other current assets	97	92
Total current assets	2,000	2,042
Long-term assets and other deferred debits		
Property, plant and equipment	5,939	5,500
Less accumulated depreciation	1,793	1,684
Property, plant and equipment – net (Note 1)	4,146	3,816
Goodwill (Note 1)	418	418
Unrecovered regulatory infrastructure program costs (Note 1)	223	196
Unrecovered environmental remediation costs (Note 1 and Note 7)	161	125
Derivative financial instruments (Note 1 and Note 2)	52	38
Other	74	75
Total long-term assets and other deferred debits	5,074	4,668
Total assets	$ 7,074	$ 6,710

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Consolidated Statements of Financial Position - Liabilities and Equity

In millions, except share amounts	As of December 31, 2009	2008
Current liabilities		
Short-term debt (Note 6)	$ 602	$ 866
Energy marketing trade payable	524	539
Accounts payable – trade	237	202
Accrued wages and salaries	56	42
Accrued regulatory infrastructure program costs – current portion (Note 1)	55	49
Derivative financial instruments – current portion (Note 1 and Note 2)	52	50
Customer deposits	41	50
Accrued interest (Note 7)	41	35
Accrued taxes	35	36
Deferred natural gas costs (Note 1)	30	25
Accrued environmental remediation liabilities – current portion (Note 1 and Note 7)	25	17
Other current liabilities	74	72
Total current liabilities	1,772	1,983
Long-term liabilities and other deferred credits		
Long-term debt (Note 6)	1,974	1,675
Accrued deferred income taxes (Note 1 and Note 8)	695	571
Accumulated removal costs (Note 1)	183	178
Accrued pension obligations (Note 3)	159	199
Accrued regulatory infrastructure program costs (Note 1)	155	140
Accrued environmental remediation liabilities (Note 1 and Note 7)	119	89
Accrued postretirement benefit costs (Note 3)	38	46
Derivative financial instruments (Note 1 and Note 2)	10	6
Other long-term liabilities and other deferred credits	150	139
Total long-term liabilities and other deferred credits	3,483	3,043
Total liabilities and other deferred credits	5,255	5,026
Commitments and contingencies (see Note 7)		
Equity		
AGL Resources Inc. common shareholders' equity, $5 par value; 750 million shares authorized	1,780	1,652
Noncontrolling interest (Note 5)	39	32
Total equity	1,819	1,684
Total liabilities and equity	$ 7,074	$ 6,710

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Consolidated Statements of Income

In millions, except per share amounts	Years ended December 31, 2009	2008	2007
Operating revenues (Note 1)	$ 2,317	$ 2,800	$ 2,494
Operating expenses			
Cost of gas (Note 1)	1,142	1,654	1,369
Operation and maintenance	497	472	451
Depreciation and amortization (Note 1)	158	152	144
Taxes other than income taxes	44	44	41
Total operating expenses	1,841	2,322	2,005
Operating income	476	478	489
Other income	9	6	4
Interest expense, net	(101)	(115)	(125)
Earnings before income taxes	384	369	368
Income tax expense (Note 8)	135	132	127
Net income	249	237	241
Less net income attributable to the noncontrolling interest (Note 5)	27	20	30
Net income attributable to AGL Resources Inc.	$ 222	$ 217	$ 211
Per common share data (Note 1)			
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.89	$ 2.85	$ 2.74
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	$ 2.88	$ 2.84	$ 2.72
Cash dividends declared per common share	$ 1.72	$ 1.68	$ 1.64
Weighted average number of common shares outstanding (Note 1)			
Basic	76.8	76.3	77.1
Diluted	77.1	76.6	77.4

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Consolidated Statements of Equity

In millions, except per share amounts	AGL Resources Inc. Shareholders Common stock Shares	Amount	Premium on common stock	Earnings reinvested	Accumulated other comprehensive Loss	Treasury shares	Noncontrolling interest	Total
Balance as of December 31, 2006	77.7	$ 390	$ 664	$ 601	$ (32)	$ (14)	$ 42	$ 1,651
Net income	-	-	-	211	-	-	30	241
Other comprehensive income (loss)	-	-	-	-	19	-	(2)	17
Dividends on common stock ($1.64 per share)	-	-	-	(127)	-	4	-	(123)
Distributions to noncontrolling interest	-	-	-	-	-	-	(23)	(23)
Issuance of treasury shares	0.7	-	(6)	(5)	-	27	-	16
Purchase of treasury shares	(2.0)	-	-	-	-	(80)	-	(80)
Stock-based compensation expense (net of tax)	-	-	9	-	-	-	-	9
Balance as of December 31, 2007	76.4	390	667	680	(13)	(63)	47	1,708
Net income	-	-	-	217	-	-	20	237
Other comprehensive loss	-	-	-	-	(121)	-	(5)	(126)
Dividends on common stock ($1.68 per share)	-	-	-	(128)	-	4	-	(124)
Distributions to noncontrolling interests	-	-	-	-	-	-	(30)	(30)
Issuance of treasury shares	0.5	-	(1)	(6)	-	16	-	9
Stock-based compensation expense (net of tax)	-	-	10	-	-	-	-	10
Balance as of December 31, 2008	76.9	390	676	763	(134)	(43)	32	1,684
Net income	-	-	-	222	-	-	27	249
Other comprehensive income	-	-	-	-	18	-	-	18
Dividends on common stock ($1.72 per share)	-	-	-	(132)	-	5	-	(127)
Distributions to noncontrolling interests	-	-	-	-	-	-	(20)	(20)
Issuance of treasury shares	0.6	-	(4)	(5)	-	17	-	8

Stock-based compensation expense (net of tax)	-	-	7	-	-	-	-	7
Balance as of December 31, 2009	77.5	$ 390	$ 679	$ 848	$ (116)	$ (21)	$ 39	$ 1,819

See Notes to Consolidated Financial Statements.

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AGL RESOURCES INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Year ended December 31,		
In millions	2009	2008	2007
Comprehensive income attributable to AGL Resources Inc. (net of tax)			
Net income attributable to AGL Resources Inc.	$ 222	$ 217	$ 211
Gain (loss) resulting from unfunded pension and postretirement obligation during the period (Note 3)	17	(111)	24
Cash flow hedges (Note 2):			
Derivative financial instruments unrealized (losses) gains arising during the period	(12)	(4)	3
Reclassification of derivative financial instruments realized losses (gains) included in net income	13	(6)	(8)
Other comprehensive income (loss)	18	(121)	19
Comprehensive income (Note 1)	$ 240	$ 96	$ 230
Comprehensive income (loss) attributable to noncontrolling interest (net of tax)			
Net income attributable to noncontrolling interest	$ 27	$ 20	$ 30
Cash flow hedges (Note 2):			
Derivative financial instruments unrealized (losses) gains arising during the period	(7)	(1)	1
Reclassification of derivative financial instruments realized losses (gains) included in net income	7	(4)	(3)
Other comprehensive loss	-	(5)	(2)
Comprehensive income (Note 1)	$ 27	$ 15	$ 28
Total comprehensive income (net of tax)			
Net income	$ 249	$ 237	$ 241
Gain (loss) resulting from unfunded pension and postretirement obligation during the period	17	(111)	24
Cash flow hedges (Note 2):			
Derivative financial instruments unrealized (losses) gains arising during the period	(19)	(5)	4
Reclassification of derivative financial instruments realized losses (gains) included in net income	20	(10)	(11)
Other comprehensive income (loss)	18	(126)	17
Comprehensive income (Note 1)	$ 267	$ 111	$ 258

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Consolidated Statements of Cash Flows

In millions	Years ended December 31, 2009	2008	2007
Cash flows from operating activities			
Net income	$ 249	$ 237	$ 241
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization (Note 1)	158	152	144
Deferred income taxes (Note 8)	105	89	30
Change in derivative financial instrument assets and liabilities (Note 2)	11	(129)	74
Changes in certain assets and liabilities			
Gas, unbilled and other receivables (Note 1)	108	(65)	(15)
Gas and trade payables	35	30	(35)
Accrued expenses	19	26	(34)
Inventories (Note 1)	(9)	(112)	46
Energy marketing receivables and energy marketing trade payables, net	(81)	10	(26)
Other – net	(3)	(11)	(48)
Net cash flow provided by operating activities	592	227	377
Cash flows from investing activities			
Expenditures for property, plant and equipment	(476)	(372)	(259)
Other	-	-	6
Net cash flow used in investing activities	(476)	(372)	(253)
Cash flows from financing activities			
Issuances of senior notes (Note 6)	297	-	125
Issuance of treasury shares (Note 1)	8	9	16
Distribution to noncontrolling interest (Note 5)	(20)	(30)	(23)
Dividends paid on common shares (Note 1)	(127)	(124)	(123)
Net payments and borrowings of short-term debt	(264)	286	52
Issuances of variable rate gas facility revenue bonds (Note 6)	-	161	-
Payments of gas facility revenue bonds (Note 6)	-	(161)	-
Payments of medium-term notes	-	-	(11)
Payments of trust preferred securities	-	-	(75)
Purchase of treasury shares (Note 1)	-	-	(80)
Other	-	1	(3)
Net cash flow (used in) provided by financing activities	(106)	142	(122)
Net increase (decrease) in cash and cash equivalents	10	(3)	2
Cash and cash equivalents at beginning of period	16	19	17
Cash and cash equivalents at end of period	$ 26	$ 16	$ 19
Cash paid during the period for			
Interest	$ 93	$ 115	$ 127
Income taxes	50	27	118

See Notes to Consolidated Financial Statements.

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Notes to Consolidated Financial Statements

Note 1 - Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all its operations through its subsidiaries. Unless the context requires otherwise, references to "we," "us," "our," the "company", or "AGL Resources" mean consolidated AGL Resources Inc. and its subsidiaries. We have prepared the accompanying consolidated financial statements under the rules of the SEC.

Basis of Presentation

Our consolidated financial statements as of and for the period ended December 31, 2009, include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. This means that our accounts are combined with the subsidiaries' accounts. We have eliminated any intercompany profits and transactions in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates' rate regulation process. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation.

Cash and Cash Equivalents

Our cash and cash equivalents consist primarily of cash on deposit, money market accounts and certificates of deposit with original maturities of three months or less.

Receivables and Allowance for Uncollectible Accounts

Our receivables consist of natural gas sales and transportation services billed to residential, commercial, industrial and other customers. We bill customers monthly, and 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. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances that could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. We write-off our customers' accounts once we deem them to be uncollectible.

Inventories

For our distribution operations subsidiaries, we record natural gas stored underground at WACOG. For Sequent and SouthStar, we account for natural gas inventory at the lower of WACOG or market price.

Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices to determine whether any declines in market prices below the WACOG are other than temporary. For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the natural gas inventory to market price. Consequently, as a result of declining natural gas prices, Sequent recorded LOCOM adjustments against cost of gas to reduce the value of its inventories to market value of $8 million in 2009, $40 million in 2008 and $4 million in 2007. SouthStar recorded LOCOM adjustments of $6 million in 2009 and $24 million in 2008, but was not required to make LOCOM adjustments in 2007.

In Georgia’s competitive environment, Marketers including SouthStar, our marketing subsidiary, began selling natural gas in 1998 to firm end-use customers at market-based prices. Part of the unbundling process, which resulted from deregulation that provides for this competitive environment, is the assignment to Marketers of certain pipeline services that Atlanta Gas Light has under contract. Atlanta Gas Light assigns, on a monthly basis, the majority of the pipeline storage services that it has under contract to Marketers, along with a corresponding amount of inventory.

Energy Marketing Receivables and Payables

Our wholesale services segment provides services to retail and wholesale marketers and utility and industrial customers. These customers, also known as counterparties, utilize netting agreements, which enable wholesale services to net receivables and payables by counterparty. Wholesale services also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. The amounts due from or owed to wholesale services’ counterparties are netted and recorded on our consolidated statements of financial position as energy marketing receivables and energy marketing payables.

Our wholesale services segment has some 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, wholesale services would need to post collateral to continue transacting business with some of its counterparties. No collateral has been posted under such provisions since our credit ratings have always exceeded the minimum requirements. As of December 31, 2009 and December 31, 2008, the collateral that wholesale services would have been required to post would not have had a material impact to our consolidated results of operations, cash flows or financial condition. However, if such collateral were not posted, wholesale services' ability to continue transacting business with these counterparties would be impaired.

Property, Plant and Equipment

A summary of our PP&E by classification as of December 31, 2009 and 2008 is provided in the following table.

In millions	2009	2008
Transmission and distribution	$ 4,579	$ 4,344
Storage	290	290
Other	725	543
Construction work in progress	345	323
Total gross PP&E	5,939	5,500
Accumulated depreciation	(1,793)	(1,684)
Total net PP&E	$ 4,146	$ 3,816

Distribution Operations PP&E expenditures consist of property and equipment that is in use, being held for future use and under construction. We report PP&E at its original cost, which includes:

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction (AFUDC) which represents the estimated cost of funds, from both debt and equity sources, used to finance the construction of major projects and is capitalized in rate base for ratemaking purposes when the completed projects are placed in service

We charge property retired or otherwise disposed of to accumulated depreciation since such costs are recovered in rates.

Retail Energy Operations, Wholesale Services, Energy Investments and Corporate PP&E expenditures include property that is in use and under construction, and we report it at cost. We record a gain or loss for retired or otherwise disposed-of property. Natural gas in storage at Jefferson Island that is retained as pad gas (volumes of non-working natural gas used to maintain the operational integrity of the cavern facility) is classified as non-depreciable property, plant and equipment and is valued at cost.

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. The composite straight-line depreciation rates for depreciable property -- excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas and Chattanooga Gas and the composite, straight-line rates for Elizabethtown Gas, Florida City Gas and Elkton Gas are listed in the following table. We depreciate transportation equipment on a straight-line basis over a period of 5 to 10 years. We compute depreciation expense for other segments on a straight-line basis up to 35 years based on the useful life of the asset.

	2009	2008	2007
Atlanta Gas Light	2.5 %	2.5 %	2.5 %
Chattanooga Gas	3.4 %	3.3 %	3.3 %
Elizabethtown Gas	3.1 %	3.1 %	3.0 %
Elkton Gas	2.1 %	2.9 %	4.0 %
Florida City Gas	3.9 %	3.9 %	3.7 %
Virginia Natural Gas	2.6 %	2.7 %	2.5 %

AFUDC and Capitalized Interest

Four of our utilities are authorized by applicable state regulatory agencies or legislatures to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated statements of financial position and as AFUDC of $13 million in 2009, $8 million in 2008 and $4 million in 2007 within the consolidated statements of income. The capital expenditures of our two other utilities do not qualify for AFUDC treatment. More information on our authorized AFUDC rates is provided in the following table.

	Authorized AFUDC rate
Atlanta Gas Light	8.53 %
Chattanooga Gas	7.89 %
Elizabethtown Gas (1)	0.41 %
Virginia Natural Gas (2)	9.24 %

(1) Variable rate as of December 31, 2009, and is determined by FERC method of AFUDC accounting.
(2) Approved only for Hampton Roads construction project.

Within our energy investments operating segment, we have recorded capitalized interest as part of the cost of the Golden Triangle Storage facilities construction project in our consolidated statements of financial position in the amount of $3 million as of December 31, 2009 and $2 million as of December 31, 2008. The capitalized interest is also reported within interest expense in our consolidated statements of income.

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Goodwill

Goodwill is the excess of the purchase price over the fair value of identifiable net assets acquired in business combinations in accordance with the authoritative guidance. We do not amortize goodwill but annually test it for impairment or when indication of potential impairment exists. These indicators would include 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 among other factors. We test goodwill impairment utilizing a fair value approach at a reporting unit level which generally equates to our operating segments as discussed in Note 9 "Segment Information." We have included $418 million of goodwill in our consolidated statement of financial position as of December 31, 2009 and 2008.

Our impairment analysis for the years ended December 31, 2009 and 2008 of our identifiable net assets acquired in business combinations indicated that the fair value substantially exceeded the carrying value. As a result, we did not recognize any impairment charges.

Fair value measurements

The carrying values of cash and cash equivalents, receivables, derivative financial assets and liabilities, accounts payable, pension and postretirement plan assets and liabilities, other current liabilities and accrued interest approximate fair value. See Notes 2, 3 and 6 for additional fair value disclosures.

As defined in 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 pricing 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 and endeavor 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 are able to 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 are available 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 financial instruments with exchange-traded derivatives.

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 market place. As we aggregate our disclosures by counterparty, the underlying transactions for a given counterparty may be a combination of exchange-traded derivatives and values based on other sources. Instruments in this category include shorter tenor exchange-traded and non-exchange-traded derivatives such as OTC forwards and options.

Level 3

Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs. We do not have any material assets or liabilities classified as level 3, except for retirement plan assets as described in Note 3.

In April 2009, additional authoritative guidance related to fair value measurements and disclosures established a two-step process to determine if the market for a financial asset is inactive and a transaction is not distressed. Currently, this authoritative guidance does not affect us, as our derivative financial instruments are traded in active markets.

Taxes

The reporting of our assets and liabilities for financial accounting purposes differs from the reporting for income tax purposes. The principal differences between net income and taxable income relate 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 differences in those items as deferred income tax assets or liabilities in our consolidated statements of financial position in accordance with authoritative guidance related to income taxes. Investment tax credits of approximately $13 million previously deducted for income tax purposes for Atlanta Gas Light, Elizabethtown Gas, Florida City Gas and Elkton Gas have been deferred for financial accounting purposes and are being amortized as credits to income over the estimated lives of the related properties in accordance with regulatory requirements.

We do not collect income taxes from our customers on behalf of governmental authorities. We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our consolidated statements of financial position except taxes in the state of Florida which we are required to include in revenues and operating expenses. These Florida related taxes are not material for any periods presented.

Revenues

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

As required by the Georgia Commission, in July 1998, Atlanta Gas Light began billing Marketers in equal monthly installments for each residential, commercial and industrial customer’s distribution costs. As required by the Georgia Commission, effective February 1, 2001, Atlanta Gas Light implemented a seasonal rate design for the calculation of each residential customer’s annual straight-fixed-variable (SFV) capacity charge, which is billed to Marketers and reflects the historic volumetric usage pattern for the entire residential class. Generally, this change results in residential customers being billed by Marketers for a higher capacity charge in the winter months and a lower charge in the summer months. This requirement has an operating cash flow impact but does not change revenue recognition. As a result, Atlanta Gas Light continues to recognize its residential SFV capacity revenues for financial reporting purposes in equal monthly installments.

The Elizabethtown Gas, Virginia Natural Gas, Florida City Gas, Chattanooga Gas and Elkton Gas rate structures include volumetric rate designs that allow recovery of costs through 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. In addition, revenues are recorded for estimated deliveries of gas not yet billed to these customers, from the last meter reading date to the end of the accounting period. These are included in the consolidated statements of financial position as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

The tariffs for Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas contain WNA’s that partially mitigate the impact of unusually cold or warm weather on customer billings and operating margin. The WNA’s purpose is to reduce the effect of weather on customer bills by reducing bills when winter weather is colder than normal and increasing bills when weather is warmer than normal. Additionally, the tariff for Virginia Natural Gas contains a revenue normalization mechanism that mitigates the impact of conservation and declining customer usage.

Retail energy operations We record retail energy operations' revenues when services are provided to customers. Revenues from sales and transportation services are recognized in the same period in which the related volumes are delivered to customers. Sales revenues from residential and certain commercial and industrial customers are recognized on the basis of scheduled meter readings. In addition, revenues are recorded 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. These are included in the consolidated statements of financial position as unbilled revenue. For other commercial and industrial customers and all wholesale customers, revenues are based on actual deliveries to the end of the period.

Wholesale services We record wholesale services' revenues when services are provided to customers. Profits from sales between segments are eliminated in the corporate segment and are recognized as goods or services sold to end-use customers. Transactions that qualify as derivatives under authoritative guidance related to derivatives and hedging are recorded at fair value with changes in fair value recognized in earnings in the period of change and characterized as unrealized gains or losses.

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Energy investments We record operating revenues at Jefferson Island in the period in which actual 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 record operating revenues at AGL Networks from leases of dark fiber pursuant to indefeasible rights-of-use (IRU) agreements as services are provided. Dark fiber IRU agreements generally require the customer to make a down payment upon execution of the agreement; however in some cases AGL Networks receives up to the entire lease payment at the inception of the lease and recognizes ratably over the lease term. AGL Networks had deferred revenue in our consolidated statements of financial position of $33 million at December 31, 2009 and December 31, 2008. In addition, AGL Networks recognizes sales revenues upon the execution of certain sales-type agreements for dark fiber when the agreements provide for the transfer of legal title to the dark fiber to the customer at the end of the agreement’s term. This sales-type accounting treatment is in accordance with authoritative guidance related to leases and revenue recognition, which provides that such transactions meet the criteria for sales-type lease accounting if the agreement obligates the lessor to convey ownership of the underlying asset to the lessee by the end of the lease term.

Cost of gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using natural gas cost recovery mechanisms set by the state regulatory agencies. Under the these mechanisms, we defer (that is, include as a current asset or liability in the consolidated statements of financial position and exclude from the statements of consolidated income) the difference between the actual cost of gas and what is collected from or billed to customers in a given period. The deferred amount is either billed or refunded to our customers prospectively through adjustments to the commodity rate.

Our retail energy operations customers are charged for natural gas consumed. We also include within our cost of gas amounts for fuel and lost and unaccounted for gas, adjustments to reduce the value of our inventories to market value and for gains and losses associated with derivatives.

Comprehensive Income

Our comprehensive income includes net income and net income attributable to AGL Resources Inc. plus OCI, which includes other gains and losses affecting shareholders’ equity that GAAP excludes from net income and net income attributable to AGL Resources Inc. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges and overfunded or unfunded pension obligation adjustments.

Earnings Per Common Share

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

We derive our potentially dilutive common shares by calculating the number of shares issuable under restricted stock, restricted stock units and stock options. The future issuance of shares underlying the restricted stock and restricted share units depends on the satisfaction of certain performance criteria. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. The following table shows the calculation of our diluted shares attributable to AGL Resources Inc. common shareholders for the periods presented if performance units currently earned under the plan ultimately vest and if stock options currently exercisable at prices below the average market prices are exercised.

In millions	2009	2008	2007
Denominator for basic earnings per common share attributable to AGL Resources Inc. common shareholders (1)	76.8	76.3	77.1
Assumed exercise of potential common shares	0.3	0.3	0.3
Denominator for diluted earnings per common share attributable to AGL Resources Inc. common shareholders	77.1	76.6	77.4

(1) Daily weighted average shares outstanding.

The following table contains the weighted average shares attributable to outstanding stock options that were excluded from the computation of diluted earnings per common share attributable to AGL Resources Inc. because their effect would have been anti-dilutive, as the exercise prices were greater than the average market price:

	December 31,		
InIn millions	2009	2008	2007 (1)
Twelve months ended	2.0	1.6	0.0

(1) 0.0 values represent amounts less than 0.1 million.

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The increase in the number of shares that were excluded from the computation is the result of a decline in the average market value of our common shares for the years ended December 31, 2009 and 2008 as compared to December 31, 2007. While the market value of our common shares rose during 2009, the average share price for 2009 was lower than 2008 and 2007.

Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated statements of financial position in accordance with authoritative guidance related to regulated operations. Our regulatory assets and liabilities, and associated liabilities for our unrecovered regulatory infrastructure program costs, unrecovered ERC and the derivative financial instrument assets and liabilities for Elizabethtown Gas' hedging program, are summarized in the following table.

	December 31,	
In millions	2009	2008
Regulatory assets		
Unrecovered regulatory infrastructure program costs	$ 266	$ 237
Unrecovered ERC (1)	172	143
Unrecovered seasonal rates	11	11
Unrecovered postretirement benefit costs	10	11
Unrecovered natural gas costs	-	19
Other	27	30
Total regulatory assets	486	451
Associated assets		
Derivative financial instruments	11	23
Total regulatory and associated assets	$ 497	$ 474
Regulatory liabilities		
Accumulated removal costs	$ 183	$ 178
Deferred natural gas costs	30	25
Regulatory tax liability	17	19
Unamortized investment tax credit	13	14
Derivative financial instruments	11	23
Other	17	22
Total regulatory liabilities	271	281
Associated liabilities		
Regulatory infrastructure program costs	210	189
ERC (1)	133	96
Total associated liabilities	343	285
Total regulatory and associated liabilities	$ 614	$ 566

(1) For a discussion of ERC, see Note 7.

Our regulatory assets are recoverable through either rate riders or base rates specifically authorized by a state regulatory commission. Base rates are designed to provide both a recovery of cost and a return on investment during the period rates are in effect. As such, all our regulatory assets are subject to review by the respective state regulatory commission during any future rate proceedings. In the event that the provisions of authoritative guidance related to regulated operations were no longer applicable, we would recognize a write-off of regulatory assets that would result in a charge to net income, and be classified as an extraordinary item.

Additionally, the regulatory liabilities would not be written-off but would continue to be recorded as liabilities but not as regulatory liabilities. Although the natural gas distribution industry is becoming increasingly competitive, our utility operations continue to recover their costs through cost-based rates established by the state regulatory commissions. As a result, we believe that the accounting prescribed under the guidance remains appropriate. It is also our opinion that all regulatory assets are recoverable in future rate proceedings, and therefore we have not recorded any regulatory assets that are recoverable but are not yet included in base rates or contemplated in a rate rider. The regulatory liabilities are refunded to ratepayers through a rate rider or base rates. If the regulatory liability is included in base rates, the amount is reflected as a reduction to the rate base in setting rates.

All the regulatory assets included in the preceding table are included in base rates except for the unrecovered regulatory infrastructure program costs, unrecovered ERC and deferred natural gas costs, which are recovered through specific rate riders on a dollar for dollar basis. The rate riders that authorize recovery of unrecovered regulatory infrastructure program costs and the deferred natural gas costs include both a recovery of costs and a return on investment during the recovery period.

We have two rate riders that authorize the recovery of unrecovered ERC. The ERC rate rider for Atlanta Gas Light only allows for recovery of the costs incurred and the recovery period occurs over the five years after the expense is incurred. ERC associated with the investigation and remediation of Elizabethtown Gas remediation sites located in the state of New Jersey are recovered under a remediation adjustment clause and include the carrying cost on unrecovered amounts not currently in rates.

Elizabethtown Gas' derivative financial instrument asset and liability reflect unrealized losses or gains that will be recovered from or passed to rate payers through the recovery of its natural gas costs on a dollar for dollar basis, once the losses or gains are realized. For more information on Elizabethtown Gas' derivative financial instruments, see Note 2.

Unrecovered postretirement benefit costs are recoverable through base rates over the next 4 to 23 years based on the remaining recovery period as designated by the applicable state regulatory commissions. Unrecovered seasonal rates 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. The unrecovered amounts are fully recoverable through base rates within one year.

Regulatory Infrastructure Programs

Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation and a subsequent settlement agreement between Atlanta Gas Light and the Georgia Commission) to undertake a pipeline replacement program that would replace all bare steel and cast iron pipe in its system by December 2013. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties. These replacements are on schedule.

The order provides for recovery of all prudent costs incurred in the performance of the program, which Atlanta Gas Light has recorded as a regulatory asset. Atlanta Gas Light will recover from end-use customers, through billings to Marketers, the costs related to the program net of any cost savings from the program. All such amounts will be recovered through a combination of straight-fixed-variable rates and a pipeline replacement revenue rider. The regulatory asset has two components:

- the costs incurred to date that have not yet been recovered through the rate rider
- the future expected costs to be recovered through the rate rider

Atlanta Gas Light has recorded a long-term regulatory asset of $223 million, which represents the expected future collection of both expenditures already incurred and expected future capital expenditures to be incurred through the remainder of the program. Atlanta Gas Light has also recorded a current asset of $43 million, which represents the expected amount to be collected from customers over the next 12 months. The amounts recovered from the pipeline replacement revenue rider during the last three years were:

- $41 million in 2009
- $30 million in 2008
- $27 million in 2007

As of December 31, 2009, Atlanta Gas Light had recorded a current liability of $55 million representing expected program expenditures for the next 12 months and a long-term liability of $155 million, representing expected program expenditures starting in 2011 through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the pipeline replacement program over the life of the assets. Operation and maintenance costs are expensed as incurred. Recoveries, which are recorded as revenue, are based on a formula that allows Atlanta Gas Light to recover operation and maintenance costs in excess of those included in its current base rates, depreciation expense and an allowed rate of return on capital expenditures. In the near term, the primary financial impact to Atlanta Gas Light from the pipeline replacement program is reduced cash flow from operating and investing activities, as the timing related to cost recovery does not match the timing of when costs are incurred. However, Atlanta Gas Light is allowed the recovery of carrying costs on the under-recovered balance resulting from the timing difference.

In June 2009, Atlanta Gas Light filed a request for a Strategic Infrastructure Development and Enhancement (STRIDE) program with the Georgia Commission to upgrade its distribution system and liquefied natural gas facilities to improve system reliability and create a platform to meet operational flexibility needs and forecasted growth. Under the program, Atlanta Gas Light would be required to file a ten-year infrastructure plan every three years for review and approval by the Georgia Commission. The program merges with Atlanta Gas Light's existing pipeline replacement program. In October 2009, the Georgia Commission approved the initial three years of the STRIDE program, estimated at approximately $176 million. The program is subject to review and modification by the Georgia Commission every three years.

In April 2009, the New Jersey BPU approved an accelerated $60 million enhanced infrastructure program for Elizabethtown Gas, which began in 2009 and is scheduled to be completed in 2011. This program was created in response to the New Jersey Governor's request for utilities to assist in the economic recovery by increasing infrastructure investments. A regulatory cost recovery mechanism will be established with estimated rates put into effect at the beginning of each year. At the end of the program the regulatory cost recovery mechanism will be trued-up and any remaining costs not previously collected will be included in base rates.

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Treasury Shares

Our Board of Directors has authorized us to purchase up to 8 million treasury shares through our repurchase plans. These plans are used to offset shares issued under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under these plans may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time. We will hold the purchased shares as treasury shares and account for them using the cost method. As of December 31, 2009, we had 5 million remaining authorized shares available for purchase. In 2007, we spent $80 million to purchase approximately 2 million treasury shares at a weighted average price per share of $39.56. We did not make any treasury share purchases in 2008 or 2009.

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 are restricted by laws in the states where we do business. In certain cases, our ability to pay dividends to our common shareholders is limited by the following:

- our ability to pay our debts as they become due in the usual course of business, satisfy our obligations under certain financing agreements, including debt-to-capitalization covenants
- our total assets are less than our total liabilities, and
- our ability to satisfy our obligations to any preferred shareholders

Use of Accounting Estimates

The preparation of our financial statements in conformity with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, and we evaluate our estimates on an ongoing basis. Each of our estimates 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 include our pipeline replacement program accruals, environmental liability accruals, uncollectible accounts and other allowance for contingencies, pension and postretirement obligations, derivative and hedging activities and provision for income taxes. Our actual results could differ from our estimates.

Subsequent Events

In May 2009, the FASB established guidance for and disclosure of events that occur after the statements of financial position date, but before financial statements are issued, or are available to be issued. This guidance should now be applied by management to the accounting for and disclosure of subsequent events, but does not apply to subsequent events or transactions that are within the scope of other applicable GAAP that provide different guidance. In accordance with the guidance, we evaluated subsequent events until the time that our financial statements were issued.

Note 2 – Derivative Financial Instruments

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.

The authoritative guidance related to derivatives and hedging requires that we offset cash collateral held in our broker accounts on our consolidated statements of financial position with the associated fair value of the instruments in the accounts. Our cash collateral amounts were $57 million as of December 31, 2009 and were $124 million as of December 31, 2008.

Derivative Financial Instruments

Our risk management activities are monitored by our Risk Management Committee, which consists of members of senior management and is charged with reviewing and enforcing our risk management activities and policies. Our use of derivative financial instruments and 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 financial instruments and physical transactions to manage natural gas price, interest rate, weather, automobile fuel price and foreign currency risks:

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

Our derivative financial instruments do not contain any material 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. For information on our energy marketing receivables and payables, which do have credit-risk-related or other contingent features, refer to Note 1. Our derivative financial instrument activities are included within operating cash flows as an adjustment to net income of $11 million in 2009, $(129) million in 2008 and $74 million in 2007.

Natural Gas Derivative Financial Instruments

The fair value of natural gas derivative financial instruments we use to manage exposures arising from changing natural gas prices reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains or losses on open contracts. We use external market quotes and indices to value substantially all the derivative financial instruments we use.

Distribution Operations In accordance with a directive from the New Jersey BPU, Elizabethtown Gas enters into derivative financial instruments to hedge the impact of market fluctuations in natural gas prices. Pursuant to the authoritative guidance related to derivatives and hedging, such derivative transactions are accounted for at fair value each reporting period in our consolidated statements of financial position. In accordance with regulatory requirements realized gains and losses related to these derivatives are reflected in natural gas costs and ultimately included in billings to customers. However, these derivative financial instruments are not designated as hedges in accordance with the guidance. As of December 31, 2009, Elizabethtown Gas had entered into OTC swap contracts to purchase approximately 18 Bcf of natural gas. Approximately 63% of these contracts have durations of one year or less, and none of these contracts extends beyond December 2011. The fair values of these derivative instruments were reflected as a current and long-term asset and liability of $11 million at December 31, 2009 and $23 million at December 31, 2008. For more information on our regulatory assets and liabilities see Note 1.

Retail Energy Operations We have designated a portion of SouthStar’s derivative financial instruments, consisting of financial swaps to manage the risk associated with forecasted natural gas purchases and sales, as cash flow hedges under the authoritative guidance related to derivatives and hedging. We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the settlement of the underlying hedged item.

SouthStar currently has minimal hedge ineffectiveness defined as when the gains or losses on the hedging instrument do not offset the losses or gains on the hedged item. This cash flow hedge ineffectiveness is recorded in cost of gas in our consolidated statements of income in the period in which it occurs. We have not designated the remainder of SouthStar’s derivative financial instruments as hedges under the authoritative guidance related to derivatives and hedging and, accordingly, we record changes in their fair value within cost of gas in our consolidated statements of income in the period of change. For more information on SouthStar’s gains and losses reported within comprehensive income that affect equity, see our consolidated statements of comprehensive income (loss). SouthStar has hedged its exposures to natural gas price risk to varying degrees in the markets in which it serves retail, commercial and industrial customers. Approximately 97% of SouthStar’s purchase instruments and 98% of its sales instruments are scheduled to mature in 2010 and the remaining 3% and 2%, respectively, from January 2011 through March 2012.

At December 31, 2009, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $21 million with no current liability representing a net position of 15 Bcf. This includes a $2 million current asset associated with a premium and related intrinsic value for weather derivatives. At December 31, 2008, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $11 million, a long-term asset of $5 million and a current liability of $2 million representing a net position of 28 Bcf. This includes a $4 million current asset associated with a premium and related intrinsic value for weather derivatives and associated intrinsic value.

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SouthStar also enters into both exchange and OTC derivative financial instruments to hedge natural gas price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For OTC transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2009, SouthStar's maximum exposure to any single OTC counterparty was $7 million.

Wholesale Services We purchase natural gas for storage when the difference in the current market price we pay to buy and transport natural gas plus the cost to store 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 contracts and other OTC derivatives to sell natural gas at that future price to substantially lock in the operating margin we will ultimately realize when the stored natural gas is actually sold. These futures contracts meet the definition of derivatives under the authoritative guidance related to derivatives and hedging and are accounted for at fair value in our consolidated statements of financial position, with changes in fair value recorded in our consolidated statements of income in the period of change. However, these futures contracts are not designated as hedges in accordance with the guidance.

The impact of changes in fair value of Sequent's derivative instruments utilized in its energy marketing and risk management activities, contract settlements and new business contracts acquired in 2009 increased the net fair value of its contracts outstanding by $36 million during 2009, $25 million during 2008 and reduced net fair value by $62 million during 2007.

At December 31, 2009, Sequent's commodity-related derivative financial instruments represented purchases (long) of 1,571 Bcf and sales (short) of 1,494 Bcf with approximately 95% of purchase instruments sales instruments are scheduled to mature in less than 2 years and the remaining 5% in 3 to 6 years. At December 31, 2009, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $208 million and a liability of $51 million. At December 31, 2008, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $206 million and a liability of $27 million.

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 portfolio. This difference in accounting can result in volatility in our reported earnings, even though the economic margin is essentially unchanged from the date the transactions were consummated.

Energy Investments Golden Triangle Storage uses derivative financial instruments to reduce its exposure during the construction of the storage caverns to the risk of changes in the price of natural gas that will be purchased in future periods for pad gas. Pad gas includes volumes of non-working natural gas used to maintain the operational integrity of the caverns

We have designated all of Golden Triangle Storage's derivative financial instruments, consisting of financial swaps as cash flow hedges under the authoritative guidance related to derivatives and hedging. The pad gas is considered to be a component of the storage cavern's construction costs; as a result, any derivative gains or losses arising from the cash flow hedges will remain in OCI until the pad gas is sold, which will not occur until the storage caverns are decommissioned. The fair value of these derivative financial instruments currently have minimal hedge ineffectiveness which is recorded in cost of gas in our consolidated statements of income in the period in which it occurs. Golden Triangle Storage began entering into these derivative financial transactions during 2009.

Weather Derivative Financial Instruments

In 2009 and 2008, SouthStar entered into weather derivative contracts as economic hedges of operating margins in the event of warmer-than-normal and colder-than-normal weather in the heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the authoritative guidance related to financial instruments. These weather derivative financial instruments are not designated as derivatives or hedges and SouthStar has recorded a current asset of $2 million at December 31, 2009 and $4 million at December 31, 2008. SouthStar recognized losses on its weather derivative financial instruments of $6 million for the year ended December 31, 2009, $8 million for the year ended December 31, 2008 and gains of $4 million for the year ended December 31, 2007 which was reflected in cost of gas on our consolidated statements of income.

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Derivative Financial Instruments – Fair Value Hierarchy

The following table sets forth, by level within the fair value hierarchy, our derivative financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. As required by the authoritative guidance, derivative financial assets and liabilities are classified in their entirety 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. For more information on a description of the fair value hierarchy, see Note 1.

	Recurring fair values			
	Natural gas derivative financial instruments			
	December 31, 2009		December 31, 2008	
In millions	Assets (1)	Liabilities	Assets (1)	Liabilities
Quoted prices in active markets (Level 1)	$ 36	$ (37)	$ 52	$ (117)
Significant other observable inputs (Level 2)	172	(52)	154	(28)
Netting of cash collateral	30	27	35	89
Total carrying value (2)	$ 238	$ (62)	$ 241	$ (56)

(1) $2 million premium at December 31, 2009 and $4 million at December 31, 2008 associated with weather derivatives have been excluded as they are based on intrinsic value, not fair value.
(2) There were no significant unobservable inputs (level 3) for any of the periods presented.

The determination of the fair values above incorporates various factors required under the guidance. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits, letters of credit and priority interests), but also the impact of our nonperformance risk on our liabilities.

Quantitative Disclosures Related to Derivative Financial Instruments

As of December 31, 2009, our derivative financial instruments were comprised of both long and short natural gas positions. A long position is a contract to purchase natural gas, and a short position is a contract to sell natural gas. As of December 31, 2009, we had net long natural gas contracts outstanding in the following quantities:

Hedge designation	Natural gas contracts (in Bcf)
Cash flow	5
Not designated	108
Total	113

Derivative Financial Instruments on the Consolidated Statements of Income

The following table presents the gain or (loss) on derivative financial instruments in our consolidated statements of income.

In millions	For the twelve months ended December 31, 2009
Designated as cash flow hedges under authoritative guidance related to derivatives and hedging	
Natural gas contracts – loss reclassified from OCI into cost of gas for settlement of hedged item	$ (31)
Not designated as hedges under authoritative guidance related to derivatives and hedging:	
Natural gas contracts – fair value adjustments recorded in operating revenues (1)	21
Natural gas contracts – net gain fair value adjustments recorded in cost of gas (2)	1
Total losses on derivative instruments	$ (9)

(1) Associated with the fair value of existing derivative instruments at December 31, 2009.

(2) Excludes $6 million of losses recorded in cost of gas associated with weather derivatives for the year ended December 31, 2009.

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The following amounts (pre-tax) represent the expected recognition in our consolidated statements of income of the deferred losses recorded in OCI associated with retail energy operations' derivative instruments, based upon the fair values of these financial instruments:

In millions	As of December 31, 2009
Designated as hedges under authoritative guidance related to derivatives and hedging	
Natural gas contracts – expected net loss reclassified from OCI into cost of gas for settlement of hedged item over next twelve months	$(8)

Derivative Financial Instruments on the Consolidated Statements of Financial Position

In accordance with regulatory requirements, $38 million of realized losses on derivative financial instruments used at Elizabethtown Gas in our distribution operations segment are reflected in deferred natural gas costs within our consolidated statements of financial position for the year ended December 31, 2009. The following table presents the fair value and statements of financial position classification of our derivative financial instruments.

In millions	Statement of financial position location (1)	As of December 31, 2009 (2)
Designated as cash flow hedges under authoritative guidance related to derivatives and hedging		
Asset Financial Instruments		
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	$ 6
Liability Financial Instruments		
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	(5)
	Total	1
Not designated as cash flow hedges under authoritative guidance related to derivatives and hedging		
Asset Financial Instruments		
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	590
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	118
Liability Financial Instruments		
Current natural gas contracts	Derivative financial instruments assets and liabilities – current portion	(510)
Noncurrent natural gas contracts	Derivative financial instruments assets and liabilities	(78)
	Total	120
Total derivative financial instruments		$ 121

(1) These amounts are netted within our consolidated statements of financial position. Some of our derivative financial instruments have asset positions which are presented as a liability in our consolidated statements of financial position, and we have derivative instruments that have liability positions which are presented as an asset in our consolidated statements of financial position.
(2) As required by the authoritative guidance related to derivatives and hedging, the fair value amounts above are presented on a gross basis. As a result, the amounts above do not include $57 million of cash collateral held on deposit in broker margin accounts as of December 31, 2009. Accordingly, the amounts above will differ from the amounts presented on our consolidated statements of financial position, and the fair value information presented for our derivative financial instruments in the recurring values table of this note.

Concentration of Credit Risk

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 nine Marketers in Georgia. The credit risk exposure to Marketers varies seasonally, with the lowest exposure in the nonpeak summer months and the highest exposure in the peak winter months. Marketers are responsible for the retail sale of natural gas to end-use customers in Georgia. These retail functions include customer service, billing, collections, and the purchase and sale of natural gas. Atlanta Gas Light's tariff allows it to obtain security support in an amount equal to no less than two times a Marketer's highest month's estimated bill from Atlanta Gas Light.

Wholesale Services Sequent has a concentration of credit risk for services it provides to marketers and to utility and industrial counterparties. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is generally concentrated in 20 of its counterparties. Sequent evaluates the credit risk of its counterparties using a 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 9.00 to 1.00, with 9.00 being equivalent to AAA/Aaa by S&P and Moody's and 1.00 being equivalent to D or Default by S&P and Moody's. For a customer without an external rating, Sequent assigns an internal rating based on Sequent's analysis of the strength of its financial ratios. At December 31, 2009, Sequent's top 20 counterparties represented approximately 58% of the total credit exposure of $534 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's counterparties or the counterparties' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2009.

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

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment-grade financial institution, but may also include cash or U.S. Government Securities held by a trustee. When Sequent 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 and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with which it conducts significant transactions.

Note 3 - Employee Benefit Plans

Accounting for employee benefit plans

The authoritative guidance related to retirement benefits requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits and quantify the plans' funding status as an asset or a liability on our consolidated statements of financial position. The guidance further requires that we measure the plans' assets and obligations that determine our funded status as of the end of the fiscal year. We are also required to recognize as a component of OCI the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit cost as explained in authoritative guidance related to pension and postretirement benefits.

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2009, we reported an after-tax gain to our OCI of $17 million ($28 million before tax), a net decrease of $48 million to accrued pension and postretirement obligations and an increase of $11 million to accumulated deferred income taxes.

Oversight of Plans

The Retirement Plan Investment Committee (the Committee) appointed by our Board of Directors is responsible for overseeing the investments of the retirement plans. Further, we have an Investment Policy (the Policy) for the retirement and postretirement benefit plans that aims 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 retirement and postretirement benefit plans' assets are actively managed to optimize long-term return while maintaining a high standard of portfolio quality and diversification.

We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. We do not have a concentration of assets in a single entity, industry, country, commodity or class of investment fund. The Policy's permissible investments include domestic and international equities (including convertible securities and mutual funds), domestic and international fixed income (corporate and U.S. government obligations), cash and cash equivalents and other suitable investments.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO), as the primary factors that drive the value of our unfunded PBO and APBO are the assumed discount rate and the actual return on plan assets. Additionally, equity market performance has a significant effect on our market-related value of plan assets (MRVPA), which is used by our largest pension plan. The MRVPA is a calculated value and differs from the actual market value of plan assets. The MRVPA also recognizes the difference between the actual market value and expected market value of our plan assets and is determined by our actuaries using a five-year moving weighted average methodology. Gains and losses on plan assets are spread through the MRVPA based on the five-year moving weighted average methodology, which affects the expected return on plan assets component of pension expense.

Pension Benefits

We sponsor two tax-qualified defined benefit retirement plans for our eligible employees, the AGL Resources Inc. Retirement Plan (AGL Retirement Plan) and the Employees' Retirement Plan of NUI Corporation (NUI Retirement Plan). A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant.

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We generally calculate the benefits under the AGL Retirement Plan based on age, years of service and pay. The benefit formula for the AGL Retirement Plan is a career average earnings formula, except for participants who were employees as of July 1, 2000, and who were at least 50 years of age as of that date. For those participants, we use a final average earnings benefit formula, and will continue to use this benefit formula for such participants until December 31, 2010, at which time any of those participants who are still actively employed will accrue future benefits under the career average earnings formula.

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

Postretirement Benefits

We sponsor a defined benefit postretirement health care plan for our eligible employees, the Health and Welfare Plan for Retirees and Inactive Employees of AGL Resources Inc. (AGL Postretirement Plan). Eligibility for these benefits is based on age and years of service.

The AGL Postretirement Plan includes medical coverage for all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. Additionally, the AGL Postretirement Plan provides life insurance for all employees if they have ten years of service at retirement. The state regulatory commissions have approved phase-ins that defer a portion of other postretirement benefits expense for future recovery. We recorded a regulatory asset for these future recoveries of $10 million as of December 31, 2009 and $11 million as of December 31, 2008. In addition, we recorded a regulatory liability of $5 million as of December 31, 2009 and $5 million as of December 31, 2008 for our expected expenses under the AGL Postretirement Plan. We expect to pay $8 million of insurance claims for the postretirement plan in 2010, but we do not anticipate making any additional contributions.

Effective December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 was signed into law. This act 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.

From January 1, through June 30, 2009, Medicare-eligible participants receive prescription drug benefits through a Medicare Part D plan offered by a third party and to which we subsidized participant premiums. Medicare-eligible retirees who opted out of the AGL Postretirement Plan were eligible to receive a cash subsidy which could be used towards eligible prescription drug expenses. Effective July 1, 2009, Medicare eligible retirees, including all of those at least age 65, receive benefits through our contribution to a retiree health reimbursement arrangement account.

Effective January 1, 2010, enhancements were made to the pre-65 medical coverage by removing the current cap on our expected costs and implementing a new cap determined by the new retiree premium schedule based on salary level and years of service. Consequently, a one-percentage-point change in the assumed health care cost trend rates does not materially affect the periodic benefit costs or our accumulated projected benefit obligation for our postretirement plan.

Contributions

Our employees do not contribute to the retirement plans. 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 (the Act) of 2006 , 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. The Act established a 100% funding target (over a 7-year amortization period) for plan years beginning after December 31, 2007. If certain conditions are met, the Worker, Retiree and Employer Recovery Act of 2008 (passed December, 2008) allowed us to measure our 2008 and 2009 minimum required contributions based on a funding target at 92% and 94%, respectively. In 2010, this will increase to 96% and for 2011, it will increase to 100%. In 2009 we contributed $24 million to our qualified pension plans. In 2008 we did not make contributions to our qualified pension plans as one was not required. For more information on our 2010 contributions to our pension plans, see Note 7.

The following tables present details about our AGL Retirement Plan and the NUI Retirement Plan (retirement plans) and the AGL Postretirement Plan (postretirement plan).

	Retirement plans		Postretirement plan	
Dollars in millions	2009	2008	2009	2008
Change in plan assets				
Fair value of plan assets, January 1,	$ 242	$ 383	$ 49	$ 70
Actual gain (loss) on plan assets	61	(115)	14	(21)
Employer contribution	26	1	7	4
Benefits paid	(26)	(27)	(7)	(4)
Fair value of plan assets, December 31, (A)	$ 303	$ 242	$ 63	$ 49
Change in benefit obligation				
Benefit obligation, January 1,	$ 442	$ 427	$ 95	$ 94
Service cost	8	7	-	-
Interest cost	26	26	6	6
Plan amendment	-	-	1	-
Actuarial loss (gain)	13	9	6	(1)
Benefits paid	(26)	(27)	(7)	(4)
Benefit obligation, December 31, (B)	$ 463	$ 442	$ 101	$ 95
% funded (A/B)	65.4 %	54.8 %	62.4 %	51.6 %
Amounts recognized in the consolidated statements of financial position consist of				
Current liability	$ (1)	$ (1)	$ -	$ -
Long-term liability	(159)	(199)	(38)	(46)
Total liability at December 31,	$ (160)	$ (200)	$ (38)	$ (46)
Assumptions used to determine benefit obligations				
Discount rate	5.8 - 6.0 %	6.2 %	5.8 %	6.2 %
Rate of compensation increase	3.7 %	3.7 %	3.7 %	3.7 %
Accumulated benefit obligation	$ 448	$ 425	Not applicable	

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

	Retirement plans			Postretirement plan		
Dollars in millions	2009	2008	2007	2009	2008	2007
Net benefit cost						
Service cost	$ 8	$ 7	$ 7	$ -	$ -	$ 1
Interest cost	26	26	26	6	6	6
Expected return on plan assets	(29)	(32)	(31)	(4)	(6)	(5)
Net amortization	(2)	(2)	(2)	(4)	(4)	(4)
Recognized actuarial loss	9	3	7	2	1	1

Net annual pension cost	$ 12	$ 2	$ 7	$ -	$ (3)	$ (1)
Assumptions used to determine benefit costs						
Discount rate	6.2 %	6.4 %	5.8 %	6.2 %	6.4 %	5.8 %
Expected return on plan assets	9.0 %	9.0 %	9.0 %	9.0 %	9.0 %	9.0 %
Rate of compensation increase	3.7 %	3.7 %	3.7 %	3.7 %	3.7 %	3.7 %

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There were no other changes in plan assets and benefit obligations recognized for our retirement and postretirement plans for the year ended December 31, 2009. The 2010 estimated OCI amortization and expected refunds for these plans are set forth in the following table.

In millions	Retirement plans	Postretirement plan
Amortization of prior service credit	$ (2)	$ (4)
Amortization of net loss	11	2
Refunds expected	-	-

The following table presents expected benefit payments for the years ended December 31, 2010 through 2019 for our retirement and postretirement plans. There will be benefit payments under these plans beyond 2019.

In millions	Retirement plans	Postretirement plan
2010	$ 27	$ 8
2011	27	8
2012	27	8
2013	27	8
2014	27	7
2015-2019	154	37
Total	$ 289	$ 76

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2009.

In millions	Retirement plans	Postretirement plan
Prior service credit	$ (17)	$ (12)
Net loss	187	33
Accumulated OCI	170	21
Net amount recognized in consolidated statements of financial position	(160)	(38)
Prepaid (accrued) cumulative employer contributions in excess of net periodic benefit cost	$ 10	$ (17)

There were no other changes in plan assets and benefit obligations recognized in our retirement and postretirement plans for the year ended December 31, 2009.

We consider a number of factors in determining and selecting assumptions for the overall expected long-term rate of return on plan assets. We consider the historical long-term return experience of our assets, the current and expected allocation of our plan assets, and expected long-term rates of return. We derive these expected long-term rates of return with the assistance of our investment advisors and generally base these rates on a 10-year horizon for various asset classes, our expected investments of plan assets and active asset management as opposed to investment in a passive index fund. We base our expected allocation of plan assets on a diversified portfolio consisting of domestic and international equity securities, fixed income, real estate, private equity securities and alternative asset classes.

We consider a variety of factors in determining and selecting our assumptions for the discount rate at December 31. We consider certain market indices, including Moody's Corporate AA long-term bond rate, the Citigroup Pension Liability rate, other high-grade bond indices and a single equivalent discount rate derived with the assistance of our actuaries by matching expected future cash flows in each year to the appropriate spot rates based in high quality (rated AA or better) corporate bonds.

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Our target asset allocations consists of approximately 30% - 95% equity, 10% - 40% fixed income, 10% - 35% real estate and other and the remaining 0% - 10% in cash. Our actual retirement and postretirement plans' asset allocations by level within the fair value hierarchy at December 31, 2009, are presented in the table below. Our retirement and postretirement plans' assets were accounted for at fair value and are classified in their entirety 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 their placement within the fair value hierarchy levels. For more information on a description of the fair value hierarchy, see Note 1.

	Retirement plans (1)					Postretirement plan				
In millions	Level 1	Level 2	Level 3	Total	% of total	Level 1	Level 2	Level 3	Total	% of total
Cash	$ 12	$ -	$ -	$ 12	4 %	$ 1	$ -	$ -	$ 1	2 %
Equity Securities										
U.S. large cap (2)	73	-	-	73	24 %	-	31	-	31	54 %
U.S. small cap (2)	44	-	-	44	14 %	-	-	-	-	-
International companies (3)	-	35	5	40	13 %	-	11	-	11	19 %
Emerging markets (4)	-	13	-	13	4 %	-	-	-	-	-
Fixed income securities										
Corporate bonds (5)	-	55	-	55	18 %	-	14	-	14	25 %
Other types of investments										
Global hedged equity (6)	-	-	33	33	11 %	-	-	-	-	-
Absolute return (7)	-	-	26	26	8 %	-	-	-	-	-
Private capital (8)	-	-	13	13	4 %	-	-	-	-	-
Total assets at fair value	$ 129	$ 103	$ 77	$ 309	100 %	$ 1	$ 56	$ -	$ 57	100 %
% of fair value hierarchy	42 %	33 %	25 %	100 %		2 %	98 %	-	100 %	

(1) Includes $6 million of medical benefit (health and welfare) component for 401h accounts to fund a portion of the postretirement obligation

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

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

(4) Includes funds that invests 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 assets in level 3 of the fair value hierarchy.

Retirement Plans

In millions	Total	International equity	Global hedged equity	Absolute return	Private capital
Beginning balance at December 31, 2008	$ 65	$ 3	$ 27	$ 23	$ 12
Actual return on plan assets:					
Relating to assets still held at the reporting date	10	2	6	3	(1)
Relating to assets sold during the period:					
Purchases, sales and settlements (net)	2	-	-	-	2
Transfers in and/or out of Level 3	-	-	-	-	-
Ending balance at December 31, 2009	$ 77	$ 5	$ 33	$ 26	$ 13

Employee Savings Plan Benefits

We sponsor the Retirement Savings Plus Plan (RSP), a defined contribution benefit plan that allows eligible participants to make contributions to their accounts up to specified limits. Under the RSP, we made matching contributions to participant accounts of $7 million in 2009 and $6 million in both 2008 and 2007.

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Note 4 - Stock-based and Other Incentive Compensation Plans and Agreements

General

We currently sponsor the following stock-based and other incentive compensation plans and agreements:

	Shares issuable upon exercise of outstanding stock options and / or SARs (1)	Shares issuable and / or SARs available for issuance (1)	Details
2007 Omnibus Performance Incentive Plan	514,987	4,147,782	Grants of incentive and nonqualified stock options, stock appreciation rights (SARs), shares of restricted stock, restricted stock units and performance cash awards to key employees.
Long-Term Incentive Plan (1999) (2)	2,039,248	-	Grants of incentive and nonqualified stock options, shares of restricted stock and performance units to key employees.
Officer Incentive Plan	60,731	211,409	Grants of nonqualified stock options and shares of restricted stock to new-hire officers.
2006 Non-Employee Directors Equity Compensation Plan	not applicable	152,740	Grants of stock to non-employee directors in connection with non-employee director compensation (for annual retainer, chair retainer and for initial election or appointment).
1996 Non-Employee Directors Equity Compensation Plan	40,213	14,304	Grants of nonqualified stock options and stock to non-employee directors in connection with non-employee director compensation (for annual retainer and for initial election or appointment). The plan was amended in 2002 to eliminate the granting of stock options.
Employee Stock Purchase Plan	not applicable	258,065	Nonqualified, broad-based employee stock purchase plan for eligible employees

(1) As of December 31, 2009

(2) Following shareholder approval of the Omnibus Performance Incentive Plan in 2008, no further grants will be made except for reload options that may be granted under the plan’s outstanding options.

Accounting Treatment and Compensation Expense

Effective January 1, 2006, we adopted authoritative guidance related to stock compensation, using the modified prospective application transition method. Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with guidance previously amended. This allowed us to account for our stock-based compensation plans under the intrinsic value method.

The authoritative guidance related to stock compensation requires us to measure and recognize stock-based compensation expense in our financial statements based on the estimated fair value at the date of grant for our stock-based awards, which include:

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

Performance-based stock awards and performance units contain market conditions. Stock options, restricted stock awards and performance units also contain a service condition. In accordance with this guidance, we recognize compensation expense over the requisite service period for:

- awards granted on or after January 1, 2006 and
- unvested awards previously granted and outstanding as of January 1, 2006

In addition, 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 following table provides additional information on compensation costs and income tax benefits related to our stock-based compensation awards. We recorded these amounts in our consolidated statements of income for the years ended December 31, 2009, 2008 and 2007.

In millions	2009	2008	2007
Compensation costs	$ 11	$ 10	$ 9
Income tax benefits	2	1	3

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The authoritative guidance requires excess tax benefits to be reported as a financing cash inflow. In 2007, our cash flows from financing activities included an immaterial amount for recognized compensation costs in excess of the benefits of tax deductions. In 2009 and 2008, we included $2 million of such benefits in cash flow provided by operating activities.

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. “Fair market value” is defined under the terms of the applicable plans as the most recent closing price per share of AGL Resources common stock as reported in The Wall Street Journal. Stock options generally have a three-year vesting period. Nonqualified options generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant. Compensation expense associated with stock options is generally recorded over the option vesting period; however, for unvested options that are granted to employees who are retirement-eligible, the remaining compensation expense is recorded in the current period rather than over the remaining vesting period.

As of December 31, 2009, we had an immaterial amount of total unrecognized compensation costs related to stock options. Cash received from stock option exercises for 2009 was $2 million, and the income tax benefit from stock option exercises was less than $1 million. The following tables summarize activity related to stock options for key employees and non-employee directors.

Stock Options

	Number of options	Weighted average exercise price	Weighted average remaining life (in years)	Aggregate intrinsic value (in millions)
Outstanding – December 31, 2006	2,325,486	$ 30.85		
Granted	735,196	39.11		
Exercised	(361,385)	27.78		
Forfeited (1)	(181,799)	36.75		
Outstanding – December 31, 2007	2,517,498	$ 33.28		
Granted	258,017	38.70		
Exercised	(212,600)	23.53		
Forfeited (1)	(86,926)	38.01		
Outstanding – December 31, 2008	2,475,989	$ 34.52	6.7	
Granted	250,440	31.09	9.1	
Exercised	(119,126)	27.20	3.5	
Forfeited (1)	(55,735)	36.50	6.9	
Outstanding – December 31, 2009	2,551,568	$ 34.48	6.0	$ 7
Exercisable – December 31, 2009	1,767,248	$ 33.94	5.3	$ 6

(1) Includes 13,716 shares which expired in 2009, 4,226 in 2008 and none in 2007.

Unvested Stock Options

	Number of unvested options	Weighted average exercise price	Weighted average remaining vesting period (in years)	Weighted average fair value
Outstanding – December 31, 2008	1,028,481	$ 37.80	1.1	$ 4.33
Granted	250,440	31.09	2.1	1.24
Forfeited	(20,286)	36.97	1.7	2.95
Vested	(474,315)	37.80	-	4.48
Outstanding – December 31, 2009	784,320	$ 35.68	1.2	$ 3.29

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Information about outstanding and exercisable options as of December 31, 2009, is as follows.

	Options outstanding			Options Exercisable	
Range of Exercise Prices	Number of options	Weighted average remaining contractual life (in years)	Weighted average exercise price	Number of options	Weighted average exercise price
$20.69 to $24.49	164,576	2.0	$ 21.79	164,576	$ 21.79
$24.50 to $28.30	162,375	3.6	26.80	162,375	26.80
$28.31 to $32.11	269,519	8.6	30.89	24,299	28.83
$32.12 to $35.92	1,074,035	5.5	34.87	874,035	34.65
$35.93 to $39.73	842,067	7.0	38.76	513,234	38.71
$39.74 to $43.54	38,996	6.6	41.45	28,729	41.44
Outstanding - Dec. 31, 2009	2,551,568	6.0	$ 34.48	1,767,248	$ 33.94

Summarized below are outstanding options that are fully exercisable.

Exercisable at:	Number of options	Weighted average exercise price
December 31, 2007	1,102,536	$ 28.48
December 31, 2008	1,447,508	$ 32.18
December 31, 2009	1,767,248	$ 33.94

In accordance with the fair value method of determining compensation expense, we use the Black-Scholes pricing model. Below are the ranges for per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during 2009, 2008 and 2007.

	2009	2008	2007
Expected life (years)	7	7	7
Risk-free interest rate % (1)	2.30	2.93 - 3.31	3.87 – 5.05
Expected volatility % (2)	12.9	12.8 - 13.0	13.2 – 14.3

Dividend yield % (3)		5.5		4.3 – 4.84		3.8 – 4.2
Fair value of options granted (4)	$	1.24	$	0.19 – $2.69	$	3.55 – $5.98

(1) US Treasury constant maturity - 7 years
(2) Volatility is measured over 7 years, the expected life of the options; weighted average volatility for 2009 was 12.9%, 2008 was 13.0% and 2007 was 14.2%.
(3) Weighted average dividend yield for 2009 was 5.5%, 2008 was 4.3% and 2007 was 4.2%.
(4) Represents per share value.

Intrinsic value for options is defined as the difference between the current market value and the grant price. Total intrinsic value of options exercised during 2009 was $1 million. With the implementation of our share repurchase program in 2006, we use shares purchased under this program to satisfy share-based 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 dollar value of restricted stock unit awards is equal to the grant date fair value of the awards, over the requisite service period, determined pursuant to the authoritative guidance related to stock compensation. The dollar value of performance cash unit awards is equal to the grant date fair value of the awards measured against progress towards the performance measure, over the requisite service period, determined pursuant to the authoritative guidance related to stock compensation. 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 2009, we granted to a select group a total of 211,230 restricted stock units (the 2009 restricted stock units), of which 204,590 of these units were outstanding as of December 31, 2009. These restricted stock units had a performance measurement period that ended December 31, 2009, which were achieved, and a performance measure related to a basic earnings per common share attributable to AGL Resources Inc. common shareholders goal that was met.

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Performance Cash Awards In general, a performance cash award represents the opportunity to receive cash, subject to the achievement of certain pre-established performance criteria. In 2009, we granted performance cash awards to a select group of officers. These awards have a performance measure that is related to annual growth in basic earnings per common share attributable to AGL Resources Inc. common shareholders and the average dividend yield. Accruals in connection with these grants are as follows:

In millions	Measurement period end date	Accrued at Dec. 31, 2009	Maximum aggregate payout
Year of grant			
2007	Dec. 31, 2009	$ 1	$ 2
2008 (1)	Dec. 31, 2010	1	3
2009 (1)	Dec. 31, 2011	1	4

(1) Adjusted to reflect the effect of economic value created during the performance measurement period by our wholesale services segment.

Stock and Restricted Stock Awards

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

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 nonforfeitable as of the date of grant. The following table summarizes activity during 2009, related to stock awards for our non-employee directors.

	Shares of restricted stock	Weighted average fair value
Issued	19,693	$ 29.43
Forfeited	-	-
Vested	19,693	$ 29.43
Outstanding	-	-

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	Weighted average fair value

		period (in years)	
Outstanding – December 31, 2007 (1)	349,036		$ 38.15
Issued	28,024		35.63
Forfeited	(6,483)		38.43
Vested	(70,199)		36.75
Outstanding – December 31, 2008 (1)	300,378	1.3	$ 38.20
Issued	191,300	2.0	31.09
Forfeited	(15,616)	1.4	36.03
Vested	(134,817)	-	39.17
Outstanding – December 31, 2009 (1) (2)	341,245	1.0	$ 33.93

(1) Subject to restriction.
(2) Includes 103,611 restricted shares with nonforfeitable dividend rights.

Employee Stock Purchase Plan (ESPP)

Under the ESPP, employees may purchase shares of our common stock in quarterly intervals at 85% of fair market value. Employee contributions under the ESPP may not exceed $25,000 per employee during any calendar year.

	2009	2008	2007
Shares purchased on the open market	63,847	66,247	52,299
Average per-share purchase price	$ 31.45	$ 33.22	$ 34.69
Purchase price discount	$ 298,968	$ 326,615	$ 313,584

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Note 5 – Variable Interest Entity

Noncontrolling Interests

As of December 31, 2009, we owned a noncontrolling 70% financial interest in SouthStar, a joint venture with Piedmont who owns the remaining 30%. SouthStar markets natural gas and related services under the trade name Georgia Natural Gas to retail customers primarily in Georgia as well as to commercial and industrial customers, principally in Florida, Ohio, Tennessee, North Carolina, South Carolina and Alabama. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. Although our ownership interest in the SouthStar partnership is 70%, under an amended and restated joint venture agreement executed in March 2004, SouthStar's earnings are currently allocated 75% to us and 25% to Piedmont except for earnings related to customers in Ohio and Florida, which are currently allocated 70% to us and 30% to Piedmont.

In July 2009, we entered into an amended joint venture agreement with Piedmont pursuant to which we purchased an additional 15% ownership interest for $58 million, effective January 1, 2010, thus increasing our interest to 85%. Piedmont will retain the remaining 15% share. Earnings are now allocated entirely in accordance with the ownership interests. As part of the agreement, our interest will remain a noncontrolling interest and we will have no further option rights to Piedmont’s remaining 15% ownership interest. The agreement was approved by the Georgia Commission in October 2009.

We are the primary beneficiary of SouthStar’s activities and have determined that SouthStar is a VIE as defined by the authoritative guidance related to consolidations, which requires us to consolidate the VIE. We determined that SouthStar was a VIE because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar, except those losses and returns related to customers in Ohio and Florida. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly-owned subsidiary, Atlanta Gas Light.

The nature of restrictions on SouthStar’s assets are immaterial. The primary risks associated with SouthStar include weather, government regulation, competition, market risk, natural gas prices, economic conditions, inflation and bad debt. See Note 9 for statements of income, statements of financial position and capital expenditure information related to the retail energy operations segment.

On January 1, 2009, we adopted additional authoritative guidance relating to consolidations, and applied the presentation and disclosure requirements retrospectively for all periods presented. The additional guidance required that the noncontrolling interest be reported as a separate component of equity on our consolidated statements of financial position.

Additionally, prior to adoption of the guidance, we recorded our earnings allocated to Piedmont as a component of earnings before income taxes in our consolidated statements of income. The additional guidance requires that any net income attributable to the noncontrolling interest be presented separately in our consolidated statements of income. As a result, net income from noncontrolling interest is reported after net income in order to report net income attributable to the parent and the noncontrolling interest. The adoption of this guidance had no effect on our calculation of basic or diluted earnings per common share amounts, which will continue to be based upon amounts attributable to AGL Resources Inc.

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Note 6 - Debt

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval, authorization or review by state and federal regulatory bodies, including state public service commissions, the SEC and the FERC as granted by the Energy Policy Act of 2005. The following table shows our long-term debt included in our consolidated statements of financial position. We estimate the fair value 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 considered our currently assigned ratings for unsecured debt of BBB+ by S&P, Baa1 by Moody's and A- by Fitch.

In millions	Year(s) due	Interest rate (1)		Weighted average interest rate (1)		Outstanding as of December 31, 2009		2008
Short-term debt								
Commercial paper	2010	0.4	%	0.7	%	$ 601	$	273
Capital leases	2010	4.9		4.9		1		1
Credit Facility	2010	-		1.2		-		500
SouthStar line of credit	2010	-		1.1		-		75
Sequent lines of credit (2)	2010	-		1.0		-		17
Total short-term debt		0.4	%	0.8	%	$ 602	$	866
Long-term debt								
Senior notes								
Issued February 2001	2011	7.1	%	7.1	%	$ 300	$	300
Issued July 2003	2013	4.5		4.5		225		225
Issued December 2004	2015	5.0		5.0		200		200
Issued June 2006 & December 2007	2016	6.4		6.4		300		300
Issued August 2009	2019	5.3		5.3		300		-
Issue September 2004	2034	6.0		6.0		250		250
Total		5.8	%	5.8	%	1,575		1,275
Gas facility revenue bonds								
Issued July 1994	2022	0.2		0.2		47		47
Issued July 1994	2024	0.4		0.6		20		20
Issued June 1992	2026	0.2		0.2		39		39
Issued June 1992	2032	0.2		0.2		55		55
Issued July 1997	2033	5.3		5.3		39		39
Total		1.2	%	1.2	%	200		200
Medium-term notes								
Issued June 1992	2012	8.3 – 8.4		8.3 – 8.4		15		15
Issued July 1997	2017	7.2		7.2		22		22
Issued February 1991	2021	9.1		9.1		30		30

Issued April - May 1992	2022	8.6 – 8.7		8.6 – 8.7			46		46
Issued November 1996	2026	6.6		6.6			30		30
Issued July 1997	2027	7.3		7.3			53		53
Total		7.8	%	7.8	%		196		196
Capital leases	2013	4.9	%	4.9	%		3		4
Total long-term debt (3)		5.5	%	5.5	%		1,974	$	1,675
Total debt		4.3	%	4.6	%	$	2,576	$	2,541

(1) As of or for the year ended December 31, 2009.

(2) Sequent's $25 million line of credit expired in June 2009.

(3) We estimate the fair value was $2,060 million as of December 31, 2009 and $1,647 million as of December 31, 2008.

Short-term Debt

Our short-term debt at December 31, 2009 and 2008 was composed of borrowings under our commercial paper program; Credit Facility; current portions of our capital lease obligations; and lines of credit for Sequent and SouthStar.

Commercial Paper and Credit Facility Our commercial paper consists of short-term, unsecured promissory notes with maturities ranging from 4 to 27 days. These unsecured promissory notes are supported by our $1 billion Credit Facility which expires in August 2011. We have the option to request an increase in the aggregate principal amount available for borrowing under the $1 billion Credit Facility to $1.25 billion on not more than three occasions during each calendar year. Several of our subsidiaries, including SouthStar participate in our commercial paper program.

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SouthStar Credit Facility SouthStar's five-year $75 million unsecured credit facility expires in November 2011. SouthStar will use this line of credit for working capital and its general corporate needs. SouthStar had no outstanding borrowings on this line of credit at December 31, 2009 and $75 million of outstanding borrowings at December 31, 2008. We do not guarantee or provide any other form of security for the repayment of this credit facility.

Long-term Debt

Our long-term debt at December 31, 2009 and 2008 matures more than one year from the statements of financial position date and consists of medium-term notes: Series A, Series B and Series C, which we issued under an indenture dated December 1, 1989; senior notes; gas facility revenue bonds; and capital leases. The trustee with respect to our senior notes is The Bank of New York Trust Company, N.A., pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all of our senior notes. The annual maturities of our long-term debt for the next five years, excluding capital leases of $3 million, are as follows:

Year	Amount (in millions)	% of total
2011	$ 300	15 %
2012	15	1
2013	225	11
2015	200	10
After 2016	1,231	63
Total	$ 1,971	100%

Gas Facility Revenue Bonds Pivotal Utility is party to a series of loan agreements with the New Jersey Economic Development Authority (NJEDA) pursuant to which the NJEDA has issued a series of gas facility revenue bonds. In 2008, we completed letter of credit agreements for the bonds with a cumulative principal amount of $161 million. These agreements provided additional credit support and increased investor demand. As a result, these bonds were successfully auctioned and issued as variable rate gas facility bonds. The bonds with principal amounts of $55 million, $47 million and $39 million have interest rates that reset daily and the bond with a principal amount of $20 million has an interest rate that resets weekly. The letter of credit agreements are set to expire in June and September 2010.

Preferred Securities As of December 31, 2009, 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.

Capital Leases Our capital leases consist primarily of a sale/leaseback transaction completed in 2002 by Florida City Gas related to its gas meters and other equipment and will be repaid at approximately $1 million per year until 2013. Pursuant to the terms of the lease agreement, Florida City Gas is required to insure the leased equipment during the lease term. In addition, at the expiration of the lease term, Florida City Gas has the option to purchase the leased meters from the lessor at their fair market value. The fair market value of the equipment will be determined on the basis of an arm's-length transaction between an informed and willing buyer.

Default Events

Our Credit Facility financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60%. Our ratio of total debt to total capitalization calculation contained in our debt covenant includes standby letters of credit, surety bonds and the exclusion of other comprehensive income pension adjustments. Adjusting for these items, our debt-to-equity calculation, as defined by our Credit Facility, was 57% at December 31, 2009 and 59% at December 31, 2008. These amounts are within our required and targeted ranges. Our debt-to-equity calculation, as calculated from our consolidated statements of financial position, was 59% at December 31, 2009 and 60% at December 31, 2008.

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include:

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

We have no trigger 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 trigger events. We are currently in compliance with all existing debt provisions and covenants.

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Note 7 - Commitments and Contingencies

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities that are reasonably likely to have a material affect on liquidity or the availability of capital resources. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual payments such as debt and lease agreements, and commitment and contingencies as of December 31, 2009.

In millions	Total	2010	2011 & 2012	2013 & 2014	2015 & thereafter
Recorded contractual obligations:					
Long-term debt	$ 1,974	$ -	$ 318	$ 225	$ 1,431
Short-term debt	602	602	-	-	-
Pipeline replacement program costs (1)	210	55	111	44	-
Environmental remediation liabilities (1)	144	25	54	38	27
Total	$ 2,930	$ 682	$ 483	$ 307	$ 1,458
Unrecorded contractual obligations and commitments (2):					
Pipeline charges, storage capacity and gas supply (3)	$ 2,049	$ 510	$ 712	$ 354	$ 473
Interest charges (4)	1,014	109	176	156	573
Operating leases (5)	115	28	40	14	33
Asset management agreements (6)	37	23	14	-	-
Pension contributions (7)	21	21	-	-	-
Standby letters of credit, performance / surety bonds	19	18	1	-	-
Total	$ 3,255	$ 709	$ 943	$ 524	$ 1,079

(1) Includes charges recoverable through rate rider mechanisms.

(2) In accordance with GAAP, these items are not reflected in our consolidated statements of financial position.

(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 amount includes SouthStar gas commodity purchase commitments of 16 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2009, and is valued at $97 million. As we do for other subsidiaries, we provide guarantees to certain gas suppliers for SouthStar in support of payment obligations.

(4) Floating rate debt is based on the interest rate as of December 31, 2009 and the maturity of the underlying debt instrument. As of December 31, 2009, we have $41 million of accrued interest on our consolidated statements of financial position that will be paid in 2010.

(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 authoritative guidance related to leases. However, this lease accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

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

(7) Based on the current funding status of the plans, we would be required to make a minimum contribution to our pension plans of approximately $21 million in 2010. We may make additional contributions in 2010.

Environmental Remediation Costs

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. The following table provides more information on our former operating sites.

In millions	Cost estimate range	Amount recorded	Expected costs over next twelve months
Georgia and Florida	$ 64 - $113	$ 64	$ 13
New Jersey	69 - 134	69	11
North Carolina	11 - 16	11	1
Total	$ 144 - $263	$ 144	$ 25

We have confirmed 13 former operating sites in Georgia and Florida where Atlanta Gas Light owned or operated all or part of these sites. One new former MGP site has been recently identified adjacent to an existing MGP remediation site. Precise engineering soil and groundwater clean up estimates are not available and considerable variability exists with this potential new site. As of December 31, 2009, the soil and sediment remediation program was substantially complete for all Georgia sites, except for a few remaining areas of recently discovered impact, although groundwater cleanup continues. Investigation is concluded for one phase of the Orlando, Florida site; however, the Environmental Protection Agency has not approved the clean up plans. For elements of the Georgia and Florida sites where we still cannot provide engineering cost estimates, considerable variability remains in future cost estimates.

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Additionally, we have identified 6 former operating sites in New Jersey where Elizabethtown Gas owned or operated all or part of these sites. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs and therefore considerable variability remains in future cost estimates. We have also identified a site in North Carolina, which is subject to a remediation order by the North Carolina Department of Energy and Natural Resources, and there are no cost recovery mechanisms for the environmental remediation.

Our ERC liabilities are customarily reported estimates of future remediation costs for these former sites based on probabilistic models of potential costs and on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, we are able to provide conventional engineering estimates of the likely costs of remediation at our former sites. These estimates contain various engineering uncertainties, but we continuously attempt to refine and update these engineering estimates. These liabilities do not include other potential expenses, such as unasserted property damage claims, personal injury or natural resource damage claims, unbudgeted legal expenses or other costs for which we may be held liable but for which we cannot reasonably estimate an amount.

Our ERC liabilities are included as a corresponding regulatory asset. These unrecovered ERC assets are a combination of accrued ERC liabilities and unrecovered cash expenditures for investigation and cleanup costs. We primarily recover these costs through rate riders and expect to collect $11 million in revenues over the next 12 months which is reflected as a current asset. We recovered $20 million in 2009, $23 million in 2008 and $28 million in 2007 from our ERC rate riders

Rental Expense

We incurred rental expense in the amounts of $20 million in 2009, $21 million in 2008 and $21 million in 2007.

Litigation

We are involved in litigation arising in the normal course of business. We believe the ultimate resolution of such litigation will not have a material adverse effect on our consolidated financial position, results of operations or cash flows.

In February 2008, a class action lawsuit was filed in the Superior Court of Fulton County in the State of Georgia against GNG alleging that it charged its customers of variable rate plans prices for natural gas that were in excess of the published price, failed to give proper notice regarding the availability of potentially lower price plans and that it changed its methodology for computing variable rates. GNG asserts that no violation of law or Georgia Commission rules has occurred. This lawsuit was dismissed in September 2008. The plaintiffs appealed the dismissal of the lawsuit and, in May 2009, the Georgia Court of Appeals reversed the lower court’s order. In June 2009, GNG filed a petition for reconsideration with the Georgia Supreme Court. In October 2009 the Georgia Supreme Court agreed to review the Court of Appeals’ decision. Accordingly, the Georgia Supreme Court held oral arguments in January 2010, and we are awaiting the court’s decision. If the Court of Appeals’ decision is not reversed, the parties will proceed with the litigation at the trial court.

In March 2008, a second class action suit was filed against GNG in the State Court of Fulton County in the State of Georgia, regarding monthly service charges. This lawsuit alleged that GNG arbitrarily assigned customer service charges rather than basing each customer service charge on a specific credit score. GNG asserted that no violation of law or Georgia Commission rules occurred and that this lawsuit was without merit. Thus, GNG filed motions to dismiss this class action suit on various grounds. This lawsuit was dismissed with prejudice in March 2009. In April 2009, the plaintiffs appealed the decision but in June 2009, the plaintiffs withdrew their appeal of the court’s dismissal order in exchange for GNG withdrawing and dropping all claims for attorney’s fees and costs in connection with the trial and appellate proceedings.

Note 8 - Income Taxes

We have two categories of income taxes in our consolidated statements of income: current and deferred. Current income tax expense consists of federal and state income tax less applicable tax credits related to the current year. Deferred income tax expense generally is equal to the changes in the deferred income tax liability and regulatory tax liability during the year.

Investment and Other Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated statements of financial position (see Note 1, "Accounting Policies and Methods of Application"). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. In 2007, we invested in a guaranteed affordable housing tax credit fund. We reduce income tax expense in our consolidated statements of income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries, including the affordable housing credits. Components of income tax expense shown in the consolidated statements of income are shown in the following table.

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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.

In millions	2009	2008	2007
Current income taxes			
Federal	$ 22	$ 37	$ 86
State	8	7	12
Deferred income taxes			
Federal	95	77	23
State	11	12	7
Amortization of investment tax credits	(1)	(1)	(1)
Total	$ 135	$ 132	$ 127

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2009, 2008 and 2007 on our consolidated statements of income are presented in the following table. Our adoption of the authoritative guidance relating to consolidations (see Note 5) had no effect on the total income tax expense reported in our consolidated statements of income or on our accrued federal and state income taxes, including accumulated deferred income taxes as reported in our consolidated statements of financial position.

In millions	2009	2008	2007
Computed tax expense at statutory rate	$ 134	$ 129	$ 129
State income tax, net of federal income tax benefit	16	15	14
Tax effect of net income attributable to the noncontrolling interest	(11)	(8)	(12)
Amortization of investment tax credits	(1)	(1)	(1)
Affordable housing credits	(2)	(2)	(1)
Flexible dividend deduction	(2)	(2)	(2)
Other – net	1	1	-
Total income tax expense on consolidated statements of income	$ 135	$ 132	$ 127

Accumulated Deferred Income Tax Assets and Liabilities

We report some of our assets and liabilities differently for financial accounting purposes than we do for income tax purposes. We report the tax effects of the differences in those items as deferred income tax assets or liabilities in our consolidated statements of financial position. We measure the assets and liabilities using income tax rates that are currently in effect. Because of the regulated nature of the utilities' business, we recorded a regulatory tax liability in accordance with authoritative guidance related to income taxes, which we are amortizing over approximately 30 years (see Note 1). Our deferred tax assets include $74 million related to an unfunded pension and postretirement benefit obligation a decrease of $11 million from 2008.

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 accumulated deferred income tax liability are as follows.

	As of December 31,	
In millions	2009	2008
Accumulated deferred income tax liabilities		
Property – accelerated depreciation and other property-related items	$ 760	$ 635
Mark to market	9	5
Other	2	32
Total accumulated deferred income tax liabilities	771	672
Accumulated deferred income tax assets		
Deferred investment tax credits	5	5
Unfunded pension and postretirement benefit obligation	74	86
Net operating loss – NUI Corporation	-	2
Other	-	11
Total accumulated deferred income tax assets	79	104
Valuation allowances (1)	(3)	(3)
Total accumulated deferred income tax assets, net of valuation allowance	76	101
Net accumulated deferred tax liability	$ 695	$ 571

(1) Valuation allowance is due to the net operating losses on a former non-operating subsidiary that are not allowed in New Jersey.

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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 the consolidated financial statements. Under this guidance, we may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. This guidance also provides guidance on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures. As of December 31, 2008 and December 31, 2009, we did not have a liability for unrecognized tax benefits. Based on current information, we do not anticipate that this will change materially in 2010.

We recognize accrued interest and penalties related to uncertain tax positions in operating expenses in the consolidated statements of income, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2009, we did not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

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 for years before 2008 or any state for years before 2002.

Note 9 - Segment Information

We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. Our operating segments comprise revenue-generating components of our company for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance. Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. We manage our businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments and a nonoperating corporate segment.

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

We are also involved in several related and complementary businesses. Our retail energy operations segment includes retail natural gas marketing to end-use customers primarily in Georgia. Our wholesale services segment includes natural gas asset management and related logistics activities for each of our utilities as well as for nonaffiliated companies, natural gas storage arbitrage and related activities. Our energy investments segment includes a number of aggregated businesses that are related and complimentary to our primary business. The most significant is the development and operation of high-deliverability natural gas storage assets. Our corporate segment includes intercompany eliminations and aggregated subsidiaries that are not significant enough on a stand-alone basis to warrant treatment as an operating segment, and that do not fit into one of our four operating segments.

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

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income, earnings before income taxes and net income for 2009, 2008 and 2007 are presented below.

In millions	2009	2008	2007
Operating income	$ 476	$ 478	$ 489
Other income	9	6	4
EBIT	485	484	493
Interest expense	101	115	125
Earnings before income taxes	384	369	368
Income taxes	135	132	127
Net income	249	237	241

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Summarized income statement, statements of financial position and capital expenditure information by segment as of and for the years ended December 31, 2009, 2008 and 2007 is shown in the following tables.

2009

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,344	$801	$121	$47	$ 4	$2,317
Intercompany revenues (1)	138	-	-	-	(138)	-
Total operating revenues	1,482	801	121	47	(134)	2,317
Operating expenses						
Cost of gas	646	620	10	1	(135)	1,142
Operation and maintenance	351	71	59	25	(9)	497
Depreciation and amortization	134	4	3	6	11	158
Taxes other than income taxes	34	1	2	2	5	44
Total operating expenses	1,165	696	74	34	(128)	1,841
Operating income (loss)	317	105	47	13	(6)	476
Other income (expense)	9	-	-	(1)	1	9
EBIT	$326	$105	$47	$12	$ (5)	$485
Identifiable and total assets	$5,230	$261	$1,168	$454	$ (39)	$7,074
Goodwill	$404	$-	$-	$14	$ -	$418
Capital expenditures	$354	$2	$1	$110	$ 9	$476

2008

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,581	$987	$170	$55	$ 7	$2,800
Intercompany revenues (1)	187	-	-	-	(187)	-
Total operating revenues	1,768	987	170	55	(180)	2,800
Operating expenses						
Cost of gas	950	838	48	5	(187)	1,654
Operation and maintenance	330	67	55	24	(4)	472
Depreciation and amortization	128	4	5	6	9	152
Taxes other than income taxes	35	2	2	1	4	44
Total operating expenses	1,443	911	110	36	(178)	2,322
Operating income (loss)	325	76	60	19	(2)	478
Other income	4	1	-	-	1	6
EBIT	$329	$77	$60	$19	$ (1)	$484
Identifiable and total assets	$5,138	$315	$970	$353	$ (66)	$6,710
Goodwill	$404	$-	$-	$14	$ -	$418
Capital expenditures	$278	$6	$1	$75	$ 12	$372

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2007

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,477	$892	$83	$ 42	$ -	$ 2,494
Intercompany revenues (1)	188	-	-	-	(188)	-
Total operating revenues	1,665	892	83	42	(188)	2,494
Operating expenses						
Cost of gas	845	704	6	2	(188)	1,369
Operation and maintenance	330	69	38	19	(5)	451
Depreciation and amortization	122	5	4	5	8	144
Taxes other than income taxes	33	1	1	1	5	41
Total operating expenses	1,330	779	49	27	(180)	2,005
Operating income (loss)	335	113	34	15	(8)	489
Other income	3	-	-	-	1	4
EBIT	$338	$113	$34	$ 15	$ (7)	$ 493
Identifiable and total assets	$4,847	$282	$890	$ 287	$ (48)	$ 6,258
Goodwill	$406	$-	$-	$ 14	$ -	$ 420
Capital expenditures	$201	$2	$2	$ 26	$ 28	$ 259

(1) Intercompany revenues – Wholesale services records its energy marketing and risk management revenues on a net basis and its total operating revenues include intercompany revenues of $425 million in 2009, $982 million in 2008 and $638 million in 2007.

Note 10 - Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2009, 2008 and 2007 are summarized below. The variance in our quarterly earnings is the result of the seasonal nature of our primary business.

In millions, except per share amounts	March 31	June 30	Sept. 30	Dec. 31
2009				
Operating revenues	$ 995	$ 377	$ 307	$ 638
Operating income	230	55	43	148
Net income attributable to AGL Resources Inc.	119	20	12	71
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.55	0.26	0.16	0.92
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	1.55	0.26	0.16	0.92
2008				
Operating revenues	$ 1,012	$ 444	$ 539	$ 805
Operating income	188	6	126	158
Net income (loss) attributable to AGL Resources Inc.	89	(11)	65	74
Basic earnings (loss) per common share attributable to AGL Resources Inc. common shareholders	1.17	(0.15)	0.85	0.97
	1.16	(0.15)	0.85	0.97

Diluted earnings (loss) per share attributable to AGL Resources Inc. common shareholders				
2007				
Operating revenues	$ 973	$ 467	$ 369	$ 685
Operating income	216	78	55	140
Net income attributable to AGL Resources Inc.	102	30	13	66
Basic earnings per common share attributable to AGL Resources Inc. common shareholders	1.31	0.40	0.17	0.86
Diluted earnings per common share attributable to AGL Resources Inc. common shareholders	1.30	0.40	0.17	0.86

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

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

None

ITEM 9A. CONTROLS AND PROCEDURES

Conclusions Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act). No system of controls, no matter how well-designed and operated, can provide absolute assurance that the objectives of the system of controls are met, and no evaluation of controls can provide assurance that the system of controls has operated effectively in all cases. Our disclosure controls and procedures however are designed to provide reasonable assurance that the objectives of disclosure controls and procedures are met.

Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2009, in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting identified in connection with the above-referenced evaluation by management of the effectiveness of our internal control over financial reporting that occurred during the fourth quarter ended December 31, 2009, 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, 2009. The unqualified reports of management and PricewaterhouseCoopers LLP thereon are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

ITEM 9B. OTHER INFORMATION.

None

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item with respect to directors will be set forth under the captions “Proposal I -Election of Directors”, - “Corporate Governance - Ethics and Compliance Program,” – “Committees of the Board” and “- Audit Committee” in the Proxy Statement for our 2010 Annual Meeting of Shareholders or in a subsequent amendment to this report. The information required by this item with respect to the executive officers is set forth at Part I, Item 4 of this report under the caption “Executive Officers of the Registrant.” The information required by this item with respect to Section 16(a) beneficial ownership reporting compliance will be set forth under the caption “Section 16(a) Beneficial Ownership Reporting Compliance” in the Proxy Statement or subsequent amendment referred to above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

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

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

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item will be set forth under the caption “Proposal 3 – Ratification of the Appointment of PricewaterhouseCoopers LLP as Our Independent Registered Public Accounting Firm for 2009” in the Proxy Statement or subsequent amendment to referred to in Item 10 above. All such information that is provided in the Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Documents Filed as Part of This Report.

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

- Report of Independent Registered Public Accounting Firm
- Management’s Report on Internal Control Over Financial Reporting
- Consolidated Statements of Financial Position as of December 31, 2009 and 2008
- Consolidated Statements of Income for the years ended December 31, 2009, 2008, and 2007
- Consolidated Statements of Equity for the years ended December 31, 2009, 2008 and 2007
- Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2009, 2008, and 2007
- Consolidated Statements of Cash Flows for the years ended December 31, 2009, 2008, and 2007
- 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, 2009.

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

Where an exhibit is filed by incorporation by reference to a previously filed registration statement or report, such registration statement or report is identified in parentheses.

3.1.a

	Amended and Restated Articles of Incorporation filed November 2, 2005, with the Secretary of State of the state of Georgia (Exhibit 3.1, AGL Resources Inc. Form 8-K dated November 2, 2005).
3.1.b	Articles of Amendment to the Amended and Restated Articles of Incorporation filed May 4, 2009, with the Secretary of State of the state of Georgia. (Exhibit 3.1.b, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2009)
3.2	Bylaws, as amended on December 10, 2008 (Exhibit 3.2, AGL Resources Inc. Form 8-K dated December 16, 2008).
4.1.a	Specimen form of Common Stock certificate (Exhibit 4.1, AGL Resources Inc. Form 10-Q for the fiscal quarter ended September 30, 2007).
4.1.b	Specimen AGL Capital Corporation 6.00% Senior Notes due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).
4.1.c	Specimen AGL Capital Corporation 4.95% Senior Notes due 2015 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).
4.1.d	Specimen AGL Capital Corporation 6.375% Senior Secured Notes due 2016 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 11, 2007).
4.1.e	Specimen AGL Capital Corporation 7.125% Senior Secured Notes due 2011 (Exhibit 4.1.f, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
4.1.f	Specimen AGL Capital Corporation 4.45% Senior Secured Notes due 2013 (Exhibit 4.1.g, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
4.1.g	Specimen AGL Capital Corporation, 5.25% Senior Notes due 2019 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated August 5, 2009).

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4.2.a	Indenture, dated as of December 1, 1989, between Atlanta Gas Light Company and Bankers Trust Company, as Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-32274).
4.2.b	First Supplemental Indenture dated as of March 16, 1992, between Atlanta Gas Light Company and NationsBank of Georgia, National Association, as Successor Trustee (Exhibit 4(a), Atlanta Gas Light Company registration statement on Form S-3, No. 33-46419).
4.2.c	Indenture, dated February 20, 2001 among AGL Capital Corporation, AGL Resources Inc. and The Bank of New York, as Trustee (Exhibit 4.2, AGL Resources Inc. registration statement on Form S-3, filed on September 17, 2001, No. 333-69500).
4.2.d	Form of Guarantee of AGL Resources Inc. dated as of August 10, 2009 regarding the AGL Capital Corporation 5.25% Senior Notes due 2019 (Exhibit 4.2, AGL Resources Inc. Form 8-K dated August 5, 2009).
4.3.a	Form of Guarantee of AGL Resources Inc. dated as of December 14, 2007 regarding the AGL Capital Corporation 6.375% Senior Note due 2016 (Exhibit 4.2, AGL Resources Inc. Form 8-K dated December 14, 2007).
4.3.b	Form of Guarantee of AGL Resources Inc. dated as of September 27, 2004 regarding the AGL Capital Corporation 6.00% Senior Note due 2034 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated September 27, 2004).
4.3.c	Form of Guarantee of AGL Resources Inc. dated as of December 20, 2004 regarding the AGL Capital Corporation 4.95% Senior Note due 2015 (Exhibit 4.1, AGL Resources Inc. Form 8-K dated December 21, 2004).
4.3.d	Form of Guarantee of AGL Resources Inc. dated as of March 31, 2001 regarding the AGL Capital Corporation 7.125% Senior Note due 2011 (Exhibit 4.3.d, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
4.3.e	Form of Guarantee of AGL Resources Inc. dated as of July 2, 2003 regarding the AGL Capital Corporation 4.45% Senior Note due 2013 (Exhibit 4.3.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
10.1	Director and Executive Compensation Contracts, Plans and Arrangements.
Director Compensation Contracts, Plans and Arrangements	
10.1.a	AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.b	First Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.o, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2002).
10.1.c	Second Amendment to the AGL Resources Inc. Amended and Restated 1996 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.k, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

10.1.d	AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (incorporated herein by reference to Annex C of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held May 3, 2006 filed on March 20, 2006).
10.1.e	First Amendment to the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan (Exhibit 10.1.i, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.f	Second Amendment to the AGL Resources Inc. 2006 Non-Employee Directors Equity Compensation Plan. (Exhibit 10.1.f, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.g	AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended December 31, 1997).
10.1.h	First Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2000).

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10.1.i	Second Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.4, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.j	Third Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.5, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2002).
10.1.k	Fourth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors (Exhibit 10.1.m, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.l	Fifth Amendment to the AGL Resources Inc. 1998 Common Stock Equivalent Plan for Non-Employee Directors. (Exhibit 10.1.l, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.m	Description of Directors' Compensation (Exhibit 10.1, AGL Resources Inc. Form 8-K dated December 1, 2004).
10.1.n	Form of Stock Award Agreement for Non-Employee Directors (Exhibit 10.1.aj, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).
10.1.o	Form on Nonqualified Stock Option Agreement for Non-Employee Directors (Exhibit 10.1.ak, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).
10.1.p	Form of Director Indemnification Agreement, dated April 28, 2004, between AGL Resources Inc., on behalf of itself and the Indemnities named therein (Exhibit 10.3, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2004).

Executive Compensation Contracts, Plans and Arrangements

10.1.aa	AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated as of January 1, 2002 (Exhibit 99.2, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2002).
10.1.ab	First amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.b, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).
10.1.ac	Second amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated (Exhibit 10.1.l, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ad	Third amendment to the AGL Resources Inc. Long-Term Incentive Plan (1999), as amended and restated. (Exhibit 10.1.ad, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.ae	AGL Resources Inc. Officer Incentive Plan (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2001).
10.1.af	First amendment to the AGL Resources Inc. Officer Incentive Plan (Exhibit 10.1.j, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ag	Second amendment to the AGL Resources Inc. Officer Incentive Plan. (Exhibit 10.1.ag, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.ah	

	AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Annex A of AGL Resources Inc.'s Schedule 14A, File No. 001-14174, filed with the Securities and Exchange Commission on March 19, 2007).
10.1.ai	First Amendment to the AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.ai, AGL Resources Inc. From 10-K for the fiscal year ended December 31, 2008).
10.1.aj	Form of Incentive Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.b, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ak	Form of Nonqualified Stock Option Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.c, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.al	Form of Performance Cash Award Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan.
10.1.am	Form of Restricted Stock Agreement (performance based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.e, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.an	Form of Restricted Stock Agreement (time based) - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.f, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).
10.1.ao	Form of Restricted Stock Unit Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan.
10.1.ap	Form of Stock Appreciation Rights Agreement - AGL Resources Inc. 2007 Omnibus Performance Incentive Plan (Exhibit 10.1.h, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2007).

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10.1.aq	Form of Incentive Stock Option Agreement, Nonqualified Stock Option Agreement and Restricted Stock Agreement for key employees (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2004).
10.1.ar	Form of Performance Unit Agreement for key employees (Exhibit 10.1.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2004).
10.1.as	Forms of Nonqualified Stock Option Agreement without the reload provision (LTIP and Officer Plan) (Exhibit 10.1, AGL Resources Inc. Form 8-K dated March 15, 2005).
10.1.at	Form of Nonqualified Stock Option Agreement with the reload provision (Officer Plan) (Exhibit 10.2, AGL Resources Inc. Form 8-K dated March 15, 2005).
10.1.au	Form of Restricted Stock Unit Agreement and Performance Cash Unit Agreement for key employees (Exhibit 10.1 and 10.2, respectively, AGL Resources Inc. Form 8-K dated February 24, 2006).
10.1.av	AGL Resources Inc. Nonqualified Savings Plan as amended and restated as of January 1, 2009. (Exhibit 10.1.av, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.aw	AGL Resources Inc. Annual Incentive Plan - 2007 (Exhibit 10.1, AGL Resources Inc. Form 8-K dated August 6, 2007).
10.1.ax	Description of Supplemental Executive Retirement Plan for John W. Somerhalder II. (Exhibit 10.1.ay, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.ay	AGL Resources Inc. Excess Benefit Plan as amended and restated as of January 1, 2009. (Exhibit 10.1.az, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.1.az	Continuity Agreement, dated December 1, 2007, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Kevin P. Madden (Exhibit 10.1.c, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
10.1.ba	Continuity Agreement, entered into as of December 1, 2009, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and John W. Somerhalder (Exhibit 10.1.a AGL Resources Inc. Form 8-K dated January 21, 2010).
10.1.bb	Continuity Agreement, entered into as of December 1, 2009, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Andrew W. Evans (Exhibit 10.1.b AGL Resources Inc. Form 8-K dated January 21, 2010).
10.1.bc	Continuity Agreement, entered into as of December 1, 2009, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Henry P. Linginfelter (Exhibit 10.1.c AGL Resources Inc. Form 8-K dated January 21, 2010).
10.1.bd	Continuity Agreement, entered into as of December 1, 2009, by and between AGL Resources Inc., on behalf of itself and AGL Services Company (its wholly owned subsidiary) and Douglas N. Schantz (Exhibit

	10.1.d AGL Resources Inc. Form 8-K dated January 21, 2010).
10.1.be	Form of AGL Resources Inc. Executive Post Employment Medical Benefit Plan (Exhibit 10.1.d, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003).
10.1.bf	Description of compensation for each of John W. Somerhalder, Andrew W. Evans, Kevin P. Madden and Douglas N. Schantz (incorporated herein by reference to the Compensation Discussion and Analysis section of the AGL Resources Inc. Proxy Statement for the Annual Meeting of Shareholders held April 29, 2009 filed on March 16, 2009).
10.1.bg	Retirement Enhancement Agreement, dated March 4, 2009, between Kevin P. Madden and AGL Resources Inc. (Exhibit 10.1, AGL Resources Inc. Form 8-K dated October 31, 2008).

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10.2	Guaranty Agreement, effective December 13, 2005, by and between Atlanta Gas Light Company and AGL Resources Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2007).
10.3	Form of Commercial Paper Dealer Agreement between AGL Capital Corporation, as Issuer, AGL Resources Inc., as Guarantor, and the Dealers named therein, dated September 25, 2000 (Exhibit 10.79, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.4	Guarantee of AGL Resources Inc., dated October 5, 2000, of payments on promissory notes issued by AGL Capital Corporation (AGLCC) pursuant to the Issuing and Paying Agency Agreement dated September 25, 2000, between AGLCC and The Bank of New York (Exhibit 10.80, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.5	Issuing and Paying Agency Agreement, dated September 25, 2000, between AGL Capital Corporation and The Bank of New York (Exhibit 10.81, AGL Resources Inc. Form 10-K for the fiscal year ended September 30, 2000).
10.6.a	Amended and Restated Master Environmental Management Services Agreement, dated July 25, 2002 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2003). (Confidential treatment pursuant to 17 CFR Sections 200.80 (b) and 240.24-b has been granted regarding certain portions of this exhibit, which portions have been filed separately with the Commission).
10.6.b	Modification to the Amended and Restated Master Environmental Management Services Agreement, dated February 1, 2005 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.b, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.6.c	Term Extension to the Amended and Restated Master Environmental Management Services Agreement, dated August 1, 2005 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.c, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.6.d	Modification to the Amended and Restated Master Environmental Management Services Agreement, dated June 30, 2005 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.d, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.6.e	Second Modification to the Amended and Restated Master Environmental Management Services Agreement, dated February 1, 2006 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.e, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.6.f	Third Modification to the Amended and Restated Master Environmental Management Services Agreement, dated February 1, 2008 by and between Atlanta Gas Light Company and The RETEC Group, Inc. (Exhibit 10.6.f, AGL Resources Inc. Form 10-K for the fiscal year ended December 31, 2008).
10.6.g	Fourth Modification to the amended and Restated Master Environmental Management Services Agreement dated as of February 1, 2009 by and between Atlanta Gas Light Company and the RETEC Group, Inc. (Exhibit 10.6, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2009).
10.6.h	Environmental Services Agreement, dated July 16, 2009, by and between Atlanta Gas Light Company and MACTEC Engineering and Consulting, Inc. (Exhibit 10.2, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2009).

10.7	Credit Agreement dated as of August 31, 2006, by and among AGL Resources Inc., AGL Capital Corporation, SunTrust Bank, as administrative agent, Wachovia Bank, National Association, as syndication agent, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Calyon New York Branch, as co-documentation agents, and the several other banks and other financial institutions named therein (Exhibit 10, AGL Resources Inc. Form 8-K dated August 31, 2006).
10.8.a	SouthStar Energy Services LLC Amended and Restated Agreement, dated April 1, 2004 by and between Georgia Natural Gas Company and Piedmont Energy Company (Exhibit 10, AGL Resources Inc. Form 10-Q for the quarter ended March 31, 2004).
10.8.b	Third Amendment to Amended and Restated Limited Liability Company Agreement, dated July 29, 2009, by and between Georgia Natural Gas Company and Piedmont Energy Company (Exhibit 10, AGL Resources Inc. Form 10-Q for the quarter ended June 30, 2009).

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10.9	Letter of Credit and Security Agreement dated as of September 4, 2008 by and among Pivotal Utility Holdings, Inc. as borrower, AGL Resources Inc. as Guarantor, Bank of America, N.A. as Administrative Agent, The Bank of Tokyo-Mitsubishi UFJ, LTD. as Syndication Agent and Bank of America, N.A. as Issuing Bank (Exhibit 10.1, AGL Resources Inc. Form 10-Q for the quarter ended September 30, 2008).
10.10	Credit Agreement as of September 30, 2008 by and among AGL Resources Inc., AGL Capital Corporation, Wachovia Bank, N.A. as Administrative Agent, Wachovia Capital Markets, LLC as sole lead arranger and sole lead bookrunner. SunTrust Bank, NA, The Bank of Tokyo-Mitsubishi UFJ, LTD., Calyon New York Brand and The Royal Bank of Scotland PLC as Co-Documentation Agents (Exhibit 10.1, AGL Resources Inc. Form 8-K dated September 30, 2008).
12	Statement of Computation of Ratio of Earnings to Fixed Charges.
14	AGL Resources Inc. Code of Ethics for its Chief Executive Officer and its Senior Financial Officers (Exhibit 14, AGL Resources Inc. Form 10-K for the year ended December 31, 2004).
21	Subsidiaries of AGL Resources Inc.
23	Consent of PricewaterhouseCoopers LLP, independent registered public accounting firm.
24	Powers of Attorney (included on signature page hereto).
31.1	Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a).
31.2	Certification of Andrew W. Evans pursuant to Rule 13a – 14(a).
32.1	Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350.
32.2	Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350.
101.INS	XBRL Instance Document. (1)
101.SCH	XBRL Taxonomy Extension Schema. (1)
101.CAL	XBRL Taxonomy Extension Calculation Linkbase. (1)
101.DEF	XBRL Taxonomy Definition Linkbase. (1)
101.LAB	XBRL Taxonomy Extension Labels Linkbase. (1)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase. (1)

(1)	Furnished, not filed.
(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 4, 2010.

AGL RESOURCES INC.

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

Power of Attorney

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints John W. Somerhalder II, Andrew W. Evans, Paul R. Shlanta and Bryan E. Seas, and each of them, his or her true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him or her and in his or her name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K for the year ended December 31, 2009, 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 4, 2010.

Signatures	Title
/s/ John W. Somerhalder II	Chairman, President and Chief Executive Officer
John W. Somerhalder II	(Principal Executive Officer)
/s/ Andrew W. Evans	Executive Vice President, Chief Financial Officer and Treasurer
Andrew W. Evans	(Principal Financial Officer)
/s/ Bryan E. Seas	Senior Vice President, Controller and Chief Accounting Officer
Bryan E. Seas	(Principal Accounting Officer)
	Director

/s/ Sandra N. Bane	
Sandra N. Bane	
/s/ Thomas D. Bell, Jr.	Director
Thomas D. Bell, Jr.	
/s/ Charles R. Crisp	Director
Charles R. Crisp	
/s/ Arthur E. Johnson	Director
Arthur E. Johnson	
/s/ Wyck A. Knox, Jr.	Director
Wyck A. Knox, Jr.	
/s/ Dennis M. Love	Director
Dennis M. Love	
/s/ Charles H. McTier	Director
Charles H. McTier	
/s/ Dean R. O'Hare	Director
Dean R. O'Hare	
/s/ D. Raymond Riddle	Director
D. Raymond Riddle	
/s/ James A. Rubright	Director
James A. Rubright	

/s/ Felker W. Ward, Jr.	Director
Felker W. Ward, Jr.	
/s/ Bettina M. Whyte	Director
Bettina M. Whyte	
/s/ Henry C. Wolf	Director
Henry C. Wolf	

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Schedule II

AGL Resources Inc. and Subsidiaries

VALUATION AND QUALIFYING ACCOUNTS - ALLOWANCE FOR UNCOLLECTIBLE ACCOUNTS AND INCOME TAX VALUATION FOR EACH OF THE THREE YEARS IN THE PERIOD ENDED DECEMBER 31, 2009.

In millions	Allowance for uncollectible accounts	Income tax valuation
Balance at December 31, 2006	$15	$3
Provisions charged to income in 2007	19	-
Accounts written off as uncollectible, net in 2007	(20)	-
Balance at December 31, 2007	14	3
Provisions charged to income in 2008	27	-
Accounts written off as uncollectible, net in 2008	(25)	-
Balance at December 31, 2008	16	3
Provisions charged to income in 2009	25	-
Accounts written off as uncollectible, net in 2009	(27)	-
Balance at December 31, 2009	$14	$3

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