AGL RESOURCES INC
Form 10-K
February 07, 2007

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, 2006

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 Class	Name of each exchange on which registered
Common Stock, $5 Par Value	**New York Stock Exchange**
8% Trust Preferred Securities	**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 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 or a non-accelerated filer.

Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨

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 as of the last business day of the registrant's most recently completed second fiscal quarter, was $2,971,414,431

The number of shares of the registrant's common stock outstanding as of January 31, 2007 was 77,752,515.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the Proxy Statement for the 2007 Annual Meeting of Shareholders ("Proxy Statement") to be held May 2, 2007, are incorporated by reference in Part III.

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GLOSSARY OF KEY TERMS

Atlanta Gas Light	Atlanta Gas Light Company
AGL Capital	AGL Capital Corporation
AGL Networks	AGL Networks, LLC
Bcf	Billion cubic feet
Chattanooga Gas	Chattanooga Gas Company
Credit Facility	Credit agreement supporting our commercial paper program
Deregulation Act	1997 Natural Gas Competition and Deregulation Act
Dominion Ohio	Dominion East of Ohio, a Cleveland, Ohio based natural gas company; a subsidiary of Dominion Resources, Inc.
EBIT	Earnings before interest and taxes, a non-GAAP measure that includes operating income, other income, equity in SouthStar’s income, minority interest in SouthStar’s earnings, donations and gain on sales of assets and excludes interest and tax expense; as an indicator of our operating performance, EBIT should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
Energy Act	Energy Policy Act of 2005
ERC	Environmental remediation costs
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Florida Commission	Florida Public Service Commission
GAAP	Accounting principles generally accepted in the United States of America
Georgia Commission	Georgia Public Service Commission
LNG	Liquefied natural gas

LOCOM	Lower of weighted average cost or current market price
Maryland Commission	Maryland Public Service Commission
Marketers	Marketers selling retail natural gas in Georgia and certificated by the Georgia Commission
Medium-term notes	Notes issued by Atlanta Gas Light with scheduled maturities between 2012 and 2027 bearing interest rates ranging from 6.6% to 9.1%
MGP	Manufactured gas plant
New Jersey Commission	New Jersey Board of Public Utilities
NYMEX	New York Mercantile Exchange, Inc.
OCI	Other comprehensive income
Operating margin	A non-GAAP measure of income, calculated as 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 statements of consolidated income. Operating margin should not be considered an alternative to, or more meaningful than, operating income or net income as determined in accordance with GAAP
Jefferson Island	Jefferson Island Storage & Hub, LLC
Piedmont	Piedmont Natural Gas
Pivotal Propane	Pivotal Propane of Virginia, Inc.
Pivotal Utility	Pivotal Utility Holdings, Inc., doing business as Elizabethtown Gas, Elkton Gas and Florida City Gas
PGA	Purchased gas adjustment
PRP	Pipeline replacement program
SEC	Securities and Exchange Commission
Sequent	Sequent Energy Management, L.P.

SFAS	Statement of Financial Accounting Standards
SouthStar	SouthStar Energy Services LLC
Tennessee Commission	Tennessee Regulatory Authority
Virginia Natural Gas	Virginia Natural Gas, Inc.
Virginia Commission	Virginia State Corporation Commission

REFERENCED ACCOUNTING STANDARDS

APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
EITF 98-10	Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities"
EITF 99-02	EITF Issue No. 99-02, "Accounting for Weather Derivatives"
EITF 02-03	EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'"
EITF 06-3	EITF Issue No. 06-3, "How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statements"
FIN 46 & FIN 46R	FASB Interpretation No. (FIN) 46, "Consolidation of Variable Interest Entities"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of SFAS Statement No. 109"
SFAS 5	Statement of Financial Accounting Standards (SFAS) No. 5, "Accounting for Contingencies"
SFAS 13	SFAS No. 13, "Accounting for Leases"

SFAS 71	SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation”
SFAS 87	SFAS No. 87, “Employers’ Accounting for Pensions”
SFAS 106	SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions”
SFAS 109	SFAS No. 109, “Accounting for Income Taxes”
SFAS 123 & SFAS 123R	SFAS No. 123, “Accounting for Stock-Based Compensation”
SFAS 131	SFAS No. 131, “Disclosures about Segments of an Enterprise and Related Information”
SFAS 133	SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities”
SFAS 141	SFAS No. 141, “Business Combinations”
SFAS 142	SFAS No. 142, “Goodwill and Other Intangible Assets”
SFAS 148	SFAS No. 148, “Accounting for Stock-Based Compensation - Transition and Disclosure”
SFAS 149	SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities”
SFAS 154	SFAS No. 154, “Accounting Changes and Error Corrections”
SFAS 157	SFAS No. 157, “Fair Value Measurements”
SFAS 158	SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans”

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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 a Fortune 1000 energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. We generate nearly all our operating revenues through the sale, distribution, transportation and storage of natural gas. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are 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, as described below, and a nonoperating corporate segment.

Distribution Operations - The distribution operations segment is the largest component of our business and includes utilities in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. These utilities are subject to regulation and oversight by state agencies in each state that 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. These agencies also are charged with establishing mechanisms by which our utilities can earn a reasonable return for our shareholders.

With the exception of our Atlanta Gas Light Company (Atlanta Gas Light) subsidiary in Georgia, earnings in our Distribution Operations segment can be affected by customer consumption patterns that are a function of weather conditions and price levels for natural gas. Atlanta Gas Light charges rates to its customers primarily as monthly fixed charges. Our non-Georgia jurisdictions have various regulatory mechanisms to provide us with a reasonable opportunity to recover our costs, but they are not direct offsets to the potential impacts on earnings of weather and customer consumption.

Retail Energy Operations - Our retail energy operations segment consists of SouthStar Energy Services LLC (SouthStar), the largest marketer of natural gas in Georgia. SouthStar's operations also are sensitive to customer consumption patterns similar to those affecting our utility operations. SouthStar uses a variety of hedging strategies, such as futures, options, swaps, weather derivative instruments and other risk management tools, to mitigate the potential effect of these issues on its operations.

Wholesale Services - Our wholesale services segment, which consists of Sequent Energy Management, L.P. (Sequent), takes advantage of arbitrage opportunities within the gas supply, storage and transportation markets to generate earnings, and its profitability is correlated to volatility in these markets. Market volatility results 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 among geographic locations and various time horizons created by this volatility. 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 hedging activities.

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 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.

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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 11, Segment Information," set forth in Item 8, "Financial Statements and Supplementary Data." Operating revenues, operating margin and earnings before interest and taxes (EBIT) for each of our segments are presented in the following table for the years ended December 31, 2006, 2005 and 2004:

In millions	Operating revenues	Operating margin (1)	EBIT (1)
2006			
Distribution operations	$ 1,624	$ 807	$ 310
Retail energy operations	930	156	63
Wholesale services	182	139	90
Energy investments	41	36	10
Corporate (2)	(156)	1	(9)
Consolidated	$ 2,621	$ 1,139	$ 464
2005			
Distribution operations	$ 1,753	$ 814	$ 299
Retail energy operations	996	146	63
Wholesale services	95	92	49
Energy investments	56	40	19
Corporate (2)	(182)	-	(11)
Consolidated	$ 2,718	$ 1,092	$ 419
2004			
Distribution operations	$ 1,111	$ 640	$ 247
Retail energy operations	827	132	52
Wholesale services	54	53	24
Energy investments	25	13	7
Corporate (2)	(185)	(1)	(16)
Consolidated	$ 1,832	$ 837	$ 314

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is
contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."
(2) Includes the elimination of intercompany revenues and intercompany cost of gas.

In 2006, we derived approximately 80% of our EBIT from our regulated natural gas distribution business and the sale of natural gas to end-use customers primarily in Georgia through SouthStar. This statistic is significant because it represents the portion of our earnings that directly results from the underlying business of supplying natural gas to retail customers. Although SouthStar is not subject to the same regulatory framework as our utilities, it is an integral part of the retail framework for providing gas service to end-use customers in the state of Georgia.

The remaining 20% of our EBIT was principally derived from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and the operation of high-deliverability natural gas underground storage as ancillary activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at the wholesale level, provide us with deepened business insight about natural gas market dynamics and facilitate our ability, in the case of asset management, to provide transparency to regulators as to how that value can be captured to benefit our utility customers through profit-sharing arrangements. Given the volatile and changing nature of the natural gas resource base in North America and globally, we believe that participation in these related businesses strengthens our business.

Natural Gas Demand

During 2006 we experienced a decline in per-household natural gas use, resulting in operating margin erosion. This decline was largely due to warmer weather - which was on average 14% warmer than in the prior year based on heating degree days - and higher than historical natural gas prices. The higher natural gas prices resulted in an average 34% increase in our residential customers' natural gas bills. The higher prices were primarily the result of market concerns about the sufficiency of the supply of natural gas due to disruptions in the availability of natural gas supplies caused by hurricanes Katrina and Rita in 2005. Additionally, our underlying business of supplying natural gas to retail customers continues to be negatively impacted by the addition of newer, more energy-efficient housing and efficiency improvements in natural gas appliances. The decline in natural gas usage has been somewhat offset by the growing trend toward larger homes that require more energy to heat despite the use of more efficient appliances.

In 2006, these factors contributed to lower volumes of natural gas deliveries to our customers as a result of customer conservation from the combination of both warmer weather and the reaction to the high prices for natural gas. The higher natural gas prices also resulted in higher bad debt expense. These factors negatively affected our EBIT.

Natural gas prices as of January 1, 2007 were approximately 44% lower than the same date in 2006 and are expected to be lower during the remainder of the current heating season (January - March). To the extent these lower natural gas prices are reflected in lower natural gas prices to our customers it may ease the impact of conservation experienced during the prior heating season may be lessened. Additionally, the lower prices could result in a return to normalized consumption and a return to normalized bad debt expense. If this occurs, we would expect that our operating margins and EBIT would be positively impacted relative to what we experienced in the November 2005 through March 2006 heating season.

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. Approximately 66% of these segments' operating revenues and 68% of these segments' EBIT for the year ended December 31, 2006 were generated during the five-month heating season and are reflected in our statements of consolidated income for the quarters ended March 31, 2006 and December 31, 2006. 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 vary significantly from quarter to quarter as a result of seasonality. Seasonality also affects the comparison of certain balance sheet items such as receivables, unbilled revenue, inventories and short-term debt across quarters. However, these items are comparable when reviewing our annual results.

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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 Securities and Exchange Commission (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. 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
404-584-3801

In Part III of this Form 10-K, we incorporate by reference certain information from our Proxy Statement for our 2007 annual meeting of shareholders. We expect to file that Proxy Statement with the SEC on or about March 19, 2007, and we will promptly make it available on our website. 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 materials we file with the SEC or otherwise release to the public, and on our website are forward-looking statements. Senior officers 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," "will," "would," and similar expressions.

You are cautioned not to place undue reliance on our forward-looking statements. Our forward-looking statements are not guarantees of future performance 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 inherent uncertainties, as well as potentially inaccurate assumptions, 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, that 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 distribution businesses are regulated by the Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005 (Energy Act). At the state level, our distribution businesses are regulated by the Georgia Public Service Commission (Georgia Commission), the Tennessee Regulatory Authority (Tennessee Commission), the New Jersey Board of Public Utilities (New Jersey Commission), the Florida Public Service Commission (Florida Commission), the Virginia State Corporation Commission (Virginia Commission) and the Maryland Public Service Commission (Maryland Commission). These authorities regulate many aspects of our distribution operations, including construction and maintenance of facilities, operations, safety, rates that we charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, relationships with our affiliates, and carrying costs we charge marketers selling retail natural gas in Georgia and certificated by the Georgia Commission (Marketers) 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 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.

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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, the Georgia legislature enacted the Natural Gas Competition and Deregulation Act (Deregulation Act). 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 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 the deregulation process and require or permit Atlanta Gas Light to provide retail gas sales service once again or require our retail energy operations segment, SouthStar, to change the nature of how it provides natural gas to certain customers. In addition, the Georgia Commission has statutory authority on an emergency basis to order Atlanta Gas Light to temporarily provide the same retail gas service that it provided prior to deregulation. If any of these events were to occur, we would incur costs to reverse the restructuring process or potentially lose the earnings opportunity embedded within the current marketing framework. Furthermore, the Georgia Commission has authority to change the terms under which we charge Marketers for certain supply-related services, which could also affect our future earnings.

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

We have an accounts receivable collection risk in Georgia due to a concentration of credit risk related to the provision of natural gas services to Marketers. At September 30, 1998 (prior to deregulation), Atlanta Gas Light had approximately 1.5 million end-use customers in Georgia. In contrast, at December 31, 2006, Atlanta Gas Light had only 11 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 36% of our consolidated operating margin for 2006. As a result, Atlanta Gas Light now depends on a concentrated number of customers for revenues. 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. The provisions of Atlanta Gas Light’s tariff allow it to obtain security support in an amount equal to a minimum of two times a Marketer’s highest month’s estimated bill. 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 a 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 57% of Sequent’s credit exposure is concentrated in 20 counterparties. Although most of this concentration is with counterparties that are either load-serving utilities or end-use customers and 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.

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

The natural gas business is highly competitive, 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 margins. 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 margins available in this portion of Sequent’s business.

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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, Elizabethtown Gas, Elkton Gas, Virginia Natural Gas, Inc. (Virginia Natural Gas), Florida City Gas and Chattanooga Gas Company (Chattanooga Gas) and shares profits it earns from the management of those assets with those customers and their respective customers, except at Elizabethtown Gas and Elkton Gas where Sequent is assessed an annual fixed-fee of approximately $4 million payable in monthly installments. Entry into and renewal of these agreements are subject to regulatory approval. 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.

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. 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 approvals, development project delays 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.

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 period or summer period, can have a significant impact on demand for and cost of natural gas.

We have a weather normalization adjustment (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 margin. Additionally, Virginia Natural Gas has a WNA mechanism for its residential customers that partially offsets the impact of unusually cold or warm weather. The WNA is 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 mitigate the impact on its margins of warmer than normal weather in the winter months. However, these instruments do not full protect SouthStar's earnings from the effects of unusually warm weather.

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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 negatively 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.

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 manufactured gas plants (MGP) which we ceased operating in the 1950s.

We have identified ten sites in Georgia and three in Florida where we own all or part of an MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. As of December 31, 2006, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. As of December 31, 2006, projected costs associated with the MGP sites were $27 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 that we assumed with our acquisition of NUI Corporation (NUI) in November 2004. Material cleanups of these sites have not been completed nor are precise estimates available for future cleanup costs. For the New Jersey sites, cleanup cost estimates range from $60 million to $118 million. Costs have been estimated for only one of the non-New Jersey sites, for which current estimates range from $10 million to $17 million.

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 under a long-term contract. In such events, we might incur additional losses to the extent of amounts, if any, already paid to or received from counterparties.

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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. Value at risk (VaR) 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. 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, 2006 had a 1-day holding period VaR of $1 million and $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 profit margin is essentially unchanged from the date the transactions were consummated.

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 which 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 reasonably control our expenses would adversely influence our future results.

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 2007.

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 more efficient 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.

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.

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 a defined benefit pension plan 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 and changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five years.

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 statement of consolidated income to the extent that the pension fund values are less than the total anticipated liability under the plans.

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

Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in 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.

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 affected. 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
- extreme weather conditions

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 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.

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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 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. See Item 7A, "Quantitative and Qualitative Disclosures About Market Risk." We cannot ensure that we will be successful in structuring such swap agreements to effectively manage our risks. 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.

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.

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 agreement supporting our commercial paper program (Credit Facility) and our indentures under which our debt is issued contain 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, obliged in such instance to satisfy a large portion of our outstanding indebtedness and unable to satisfy all our outstanding obligations simultaneously.

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

Standard & Poor's Ratings Services (S&P), Moody's Investor Service (Moody's) and Fitch Ratings (Fitch) currently assign our senior unsecured debt a rating of BBB+, Baa1 and A-, respectively. Our commercial paper currently is rated A2, P2 and F2 by S&P, Moody's and Fitch, respectively. 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, 2006, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $10 million to continue conducting our wholesale services business with certain counterparties.

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.

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ITEM 2. PROPERTIES

Distribution Operations As of December 31, 2006, the properties of our distribution operations segment represented approximately 90% of the net property, plant and equipment in our consolidated balance sheet. This property primarily includes assets used for the distribution of natural gas to our customers in our service areas, including more than 43,000 miles of distribution and transmission mains. We have approximately 7.35 billion cubic feet (Bcf) of liquefied natural gas (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 4.5 million gallons. These LNG plants and propane facilities supplement the gas supply during peak usage periods.

Energy Investments The properties in our energy investments segment are primarily investments that are complementary to our distribution operations or provide services consistent with our core enterprises, including a natural gas storage and hub facility in Louisiana located approximately eight miles from the Henry Hub. The Henry Hub is the largest centralized point for natural gas spot and futures trading in the United States. The New York Mercantile Exchange, Inc. (NYMEX) uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas. Our natural gas storage and hub facility consists of two salt dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. We completed a project during 2005 to expand compression capability, enabling us to increase the number of times a customer can inject and withdraw their total gas inventory annually from 10 to 12.

We also own a propane facility in Virginia. The propane facility provides our utility in Virginia with 0.03 Bcf of propane air per day on a 10-day per year basis. This system is important to our Virginia operations because it provides propane as a substitute for natural gas when natural gas demand is peaking.

In addition, energy investments' properties include telecommunications conduit and fiber in public rights-of-way that are leased to our customers primarily in Atlanta and Phoenix. This includes over 76,000 fiber miles, of which approximately 32% of our dark fiber in Atlanta and 24% of our dark fiber in Phoenix has been leased.

Retail Energy Operations, Wholesale Services and Corporate The properties used at our retail energy operations, wholesale services and corporate segments consist primarily of leased and owned office space in Atlanta and Houston and their contents, including furniture and fixtures. The majority of our Atlanta-based employees are located at our corporate headquarters, a leased building with approximately 227,000 square feet of office space. In addition, our retail energy operations segment leases approximately 30,200 square feet at another office building in Atlanta. We lease approximately 32,000 square feet of office space for our employees in Houston.

We own or lease additional office, warehouse and other facilities throughout our operating areas. We consider our properties and the properties of our subsidiaries to be well maintained, in good operating condition and suitable for their intended purpose. We expect additional or substitute space to be available as needed to accommodate expansion of our operations.

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Below is a map illustrating our total asset base and existing service territories as of December 31, 2006:

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. Information regarding some of these proceedings is contained in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Results of Operations" and in Note 8 to our consolidated financial statements under the caption "Litigation" set forth in Item 8, "Financial Statements and Supplementary Data."

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, 2006.

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ITEM 4A. 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 51 (1)	
President and Chief Executive Officer	March 2006 - Present
Andrew W. Evans, Age 40 (2)	
Executive Vice President and Chief Financial Officer	May 2006 - Present
Senior Vice President and Chief Financial Officer	September 2005 - May 2006
Vice President and Treasurer	April 2002 - September 2005
Kevin P. Madden, Age 54	
Executive Vice President, External Affairs	November 2005 - Present
Executive Vice President, Distribution and Pipeline Operations	April 2002 - November 2005
Executive Vice President, Legal, Regulatory and Governmental Strategy	September 2001 - April 2002
R. Eric Martinez, Jr., Age 38	
Executive Vice President, Utility Operations	November 2005 - Present
Senior Vice President, Business Process Initiatives	August 2005 - November 2005
Vice President and General Manager of Elizabethtown Gas	December 2004 - August 2005
Senior Vice President, Engineering & Construction of Pivotal Energy Development	August 2003 - December 2004
Chief Operating Officer of AGL Networks, LLC	December 2002 - August 2003

Vice President and General Manager of AGL Networks, LLC	June 2002 - December 2002
Vice President, Business Development	October 2000 - June 2002
Paul R. Shlanta, Age 49	
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
Senior Vice President, General Counsel and Corporate Secretary	July 2002 - September 2002
Senior Vice President and General Counsel	September 1998 - July 2002
Melanie M. Platt, Age 52	
Senior Vice President, Human Resources	September 2004 - Present
Senior Vice President and Chief Administrative Officer	November 2002 - September 2004
Vice President of Investor Relations	May 1998 - November 2002
Vice President and Corporate Secretary	January 1995 - June 2002
Douglas N. Schantz, Age 51 (3)	
President, Sequent Energy Management, LP	May 2003 - Present

(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.

(2) Mr. Evans was vice president of corporate development of Mirant Corporation's (NYSE: MIR) (formerly Southern Energy, Inc.) Mirant Americas business unit from June 2001 until April 2002.

(3) Mr. Schantz served as vice president of the gas origination division at Cinergy Marketing & Trading, LP, an affiliate of Cinergy Corp (NYSE: CIN), from September 2000 to April 2003.

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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 ATG. At January 31, 2007, there were 7,512 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2006 and 2005 is as follows:

	Sales price of common stock		Cash dividend per common share
Quarter ended:	**High**	**Low**	
2006			
March 31, 2006	$ 36.48	$ 34.40	$ 0.37
June 30, 2006	38.13	34.43	0.37
September 30, 2006	40.00	34.76	0.37
December 31, 2006	40.09	36.04	0.37
2005			
March 31, 2005	$ 36.09	$ 32.00	$ 0.31
June 30, 2005	38.89	33.37	0.31
September 30, 2005	39.32	35.29	0.31
December 31, 2005	37.54	32.23	0.37

We have historically paid dividends to common shareholders four times a year: March 1, June 1, September 1 and December 1. We have paid 237 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 and total shareholders' equity covenants

· our ability to satisfy our obligations to any 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

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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, 2006. 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 will hold the repurchased shares as treasury shares.

Period	Total number of shares purchased (1) (2) (3)	Average price paid per share	Total number of shares purchased as part of publicly announced plans or programs (3)	Maximum number of shares that may yet be purchased under the publicly announced plans or programs (3)
October 2006	111,000	$ 37.02	109,100	7,160,400
November 2006	108,421	$ 37.74	105,000	7,055,400
December 2006	98,480	$ 39.10	82,900	6,972,500
Total fourth quarter	**317,901**	**$ 37.92**	297,000	

(1) The total number of shares purchased includes an aggregate of 8,100 shares surrendered to us to satisfy tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options.

(2) 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 20,000 and 12,801 shares for such purposes in the third and fourth quarters of 2006, respectively. As of December 31, 2006, we had purchased a total 286,567 of the 600,000 shares authorized for purchase, leaving 313,433 shares available for purchase under this program.

(3) 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 (2) above, over a five-year period.

The information required by this item regarding securities authorized for issuance under our equity compensation plans will be set forth under the caption “Executive Compensation - Equity Compensation Plan Information” in the Proxy Statement for our 2007 Annual Meeting of Shareholders or in a subsequent amendment to this report. All such information will be incorporated by reference from the Proxy Statement in Item 12, “Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters” hereof or set forth in such amendment to this report.

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ITEM 6. SELECTED FINANCIAL DATA

Selected financial data about AGL Resources 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	2006	2005	2004	2003	2002
Income statement data					
Operating revenues	$ 2,621	$ 2,718	$ 1,832	$ 983	$ 877
Cost of gas	1,482	1,626	995	339	268
Operating margin (1)	1,139	1,092	837	644	609
Operating expenses					
Operation and maintenance	473	477	377	283	274
Depreciation and amortization	138	133	99	91	89
Taxes other than income taxes	40	40	29	28	29
Total operating expenses	651	650	505	402	392
Gain on sale of Caroline Street campus	-	-	-	16	-
Operating income	488	442	332	258	217
Equity in earnings of SouthStar Energy Services LLC	-	-	-	46	27
Other (expense) income	(1)	(1)	-	(6)	3
Minority interest	(23)	(22)	(18)	-	-
Earnings before interest and taxes (EBIT) (1)	464	419	314	298	247
Interest expense	123	109	71	75	86
Earnings before income taxes	341	310	243	223	161
Income taxes	129	117	90	87	58
Income before cumulative effect of change in accounting principle	212	193	153	136	103
Cumulative effect of change in accounting principle, net of $5 in income taxes	-	-	-	(8)	-
Net income	$ 212	$ 193	$ 153	$ 128	$ 103
Common stock data					
Weighted average shares outstanding basic	77.6	77.3	66.3	63.1	56.1
Weighted average shares outstanding diluted	78.0	77.8	67.0	63.7	56.6
Total shares outstanding (2)	77.7	77.8	76.7	64.5	56.7
Earnings per share basic	$ 2.73	$ 2.50	$ 2.30	$ 2.03	$ 1.84
Earnings per share diluted	$ 2.72	$ 2.48	$ 2.28	$ 2.01	$ 1.82
Dividends declared per share	$ 1.48	$ 1.30	$ 1.15	$ 1.11	$ 1.08
Dividend payout ratio	54%	52%	50%	55%	59%
Dividend yield	3.8%	3.7%	3.5%	3.8%	4.4%
Book value per share (3)	$ 20.72	$ 19.27	$ 18.04	$ 14.66	$ 12.52
Price-earnings ratio	14.3	13.9	14.5	14.3	13.2
Market value per share (4)	$ 38.91	$ 34.81	$ 33.24	$ 29.10	$ 24.30

Market value (2)	$	3,023	$	2,708	$	2,551	$	1,877	$	1,378
Balance sheet data (2)										
Total assets	$	6,147	$	6,320	$	5,637	$	3,972	$	3,742
Property, plant and equipment - net		3,436		3,333		3,178		2,345		2,194
Working capital		195		73		(20)		(306)		(429)
Total debt		2,161		2,137		1,957		1,340		1,413
Common shareholders' equity		1,609		1,499		1,385		945		710
Cash flow data										
Net cash provided by operating activities	$	354	$	80	$	287	$	122	$	286
Property, plant and equipment expenditures		253		267		264		158		187
Net payments and borrowings of short-term debt		6		188		(480)		(82)		4
Cash paid for interest		108		89		50		60		73
Financial ratios (2)										
Total debt		57%		59%		59%		59%		67%
Common shareholders' equity		43%		41%		41%		41%		33%
Total		100%		100%		100%		100%		100%
Return on average common shareholders' equity		13.6%		13.4%		13.1%		15.5%		14.7%

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income 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) Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period.

(4) Closing price of common stock on the New York Stock Exchange as of the last trading day of the fiscal period.

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

Overview

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 more than 2.2 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for nonaffiliated companies; natural gas storage arbitrage and related activities; and the development and operation of high-deliverability underground 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 - distribution operations, retail energy operations, wholesale services and energy investments - and a nonoperating corporate segment. As of December 31, 2006, we employed a total of 2,369 employees across these five segments.

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 and price levels for natural gas. Our non-Georgia jurisdictions have various regulatory mechanisms to provide us with a reasonable opportunity to recover our costs, but these methods of recovery are not direct offsets to the potential impacts on earnings. Atlanta Gas Light charges rates to its customers primarily as monthly fixed charges. 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 weather sensitive, with increased earnings opportunities, as well as increased loss potential, during periods of extreme weather conditions, which typically produce greater price volatility. Our energy investments segment's primary business is our natural gas storage, 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.

2006 Business Highlights

We achieved several significant milestones during 2006 that position us well for future growth and for providing long-term value to our shareholders.

- We completed our rate proceeding in Virginia, which resulted in a five-year rate freeze for customers under the first performance based rate (PBR) plan approved in that state for a natural gas utility. As part of the settlement reached with the parties in the case, we have committed to spend approximately $48 million to $60 million to build a new pipeline that will improve access to natural gas in certain areas we serve in Virginia, particularly during critical peak periods. Also, the Virginia Commission approved a permanent WNA for residential customers as part of the settlement.

- We successfully resolved our rate proceeding in Tennessee, which resulted in a $3 million base rate increase effective January 1, 2007 to offset higher costs and lower natural gas consumption. Additionally, the rate proceeding improved our authorized return and improved our capital structure (55% debt and 45% equity) in a manner that is more consistent with our utilities and other non-affiliated utilities.

- We continued to grow our asset management business at Sequent, which enables them to generate greater levels of economic value during periods of market volatility.

- We expanded, through SouthStar, our retail footprint into the Ohio and Florida markets.

- We announced our intention to develop a 12 Bcf natural gas salt-dome storage facility, known as Golden Triangle Storage, in Beaumont, Texas, at a capital cost of approximately $180 million. The project will provide high-deliverability Gulf Coast storage at a key market point, with the first phase scheduled to be in commercial operation in 2010.

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2006 Business Results

In 2006, we earned $212 million in net income or $2.72 per diluted share, compared with net income of $193 million, or $2.48 per diluted share, in 2005. The 10% increase in net income was the result of a variety of factors:

- Our distribution operations segment's EBIT improved by $11 million or 4% in 2006 as compared to 2005. We continued to benefit from the improved operating metrics of the utilities we acquired in 2004. These results were offset, however, by customer consumption declines due to warmer-than-normal weather throughout the year and high natural gas prices, particularly during the first quarter of 2006.

- Our retail energy operations segment provided stable year-over-year earnings contributions despite the effects of declining customer consumption, warmer weather and a lower of weighted average cost or current market price (LOCOM) adjustment to inventory. This segment's marketing efforts during the year also resulted in a slight increase in customer count.

- Our wholesale services segment captured significant arbitrage opportunities due to price volatility and periods of extreme weather conditions. As a result, this segment's EBIT contribution of $90 million was $41 million higher than in 2005, primarily as a result of additional commercial activity and storage arbitrage opportunities throughout the year, as well as the recognition of hedge gains as forward NYMEX prices declined.

- Our energy investments segment made progress on the evaluation and development of several projects during 2006. While these projects are expected to provide future earnings contributions, the associated business development expenses resulted in a lower year-over-year performance in this segment as well as the disposition in the second half of 2005 of certain non-strategic assets acquired as part of the acquisition of NUI in December 2004.

- Our interest expense for 2006 increased $14 million as compared to 2005. The increase reflects higher carrying costs associated with higher inventory storage balances, as well as higher short-term interest rates, relative to the prior year.

Results of Operations

AGL Resources

Revenues 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.

Operating Margin and EBIT We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally passed 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 gross profit 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.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with accounting principles generally accepted in the United States of America (GAAP). 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 as determined in accordance with GAAP. In addition, our operating margin or EBIT measure may not be comparable to similarly titled measures of other companies. The following table sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the years ended December 31, 2006, 2005 and 2004.

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In millions	2006	2005	2004
Operating revenues	$ 2,621	$ 2,718	$ 1,832
Cost of gas	1,482	1,626	995
Operating margin	1,139	1,092	837
Operating expenses			
Operation and maintenance	473	477	377
Depreciation and amortization	138	133	99
Taxes other than income	40	40	29
Total operating expenses	651	650	505
Operating income	488	442	332
Other expenses	(1)	(1)	-
Minority interest	(23)	(22)	(18)
EBIT	464	419	314
Interest expense	123	109	71
Earnings before income taxes	341	310	243
Income taxes	129	117	90
Net income	$ 212	$ 193	$ 153
Earnings per common share:			
Basic	$ 2.73	$ 2.50	$ 2.30
Diluted	$ 2.72	$ 2.48	$ 2.28
Weighted average number of common shares outstanding:			
Basic	77.6	77.3	66.3
Diluted	78.0	77.8	67.0

Segment information Operating revenues, operating margin, operating expenses and EBIT information for each of our segments are presented in the following table for the years ended December 31, 2006, 2005 and 2004:

In millions	Operating revenues	Operating margin (1)	Operating expenses	EBIT (1)
2006				
Distribution operations	$ 1,624	$ 807	$ 499	$ 310
Retail energy operations	930	156	68	63
Wholesale services	182	139	49	90
Energy investments	41	36	26	10
Corporate (2)	(156)	1	9	(9)
Consolidated	$ 2,621	$ 1,139	$ 651	$ 464
2005				
Distribution operations	$ 1,753	$ 814	$ 518	$ 299
Retail energy operations	996	146	61	63
Wholesale services	95	92	42	49
Energy investments	56	40	23	19
Corporate (2)	(182)	-	6	(11)
Consolidated	$ 2,718	$ 1,092	$ 650	$ 419
2004				
Distribution operations	$ 1,111	$ 640	$ 394	$ 247
Retail energy operations	827	132	62	52
Wholesale services	54	53	29	24
Energy investments	25	13	8	7

Corporate (2)		(185)		(1)		12		(16)
Consolidated	$	1,832	$	837	$	505	$	314

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in Results of Operations - AGL Resources.

(2) Includes the elimination of intercompany revenues and cost of gas.

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Discussion of Consolidated Results

2006 compared to 2005 The increase in EBIT of $45 million or 11% in 2006 was primarily the result of increases at the distribution operations and wholesale services segments. Wholesale services' EBIT improvement of $41 million primarily reflected the recognition of hedge gains during 2006, as forward NYMEX prices declined significantly. In contrast, NYMEX price increases experienced during 2005 had the opposite effect, but to a lesser extent. In the distribution operations segment, EBIT improved by $11 million, and operating margin declined $7 million offset primarily by reduced operating expenses of $19 million. Our retail energy operations segment's EBIT was flat compared to 2005. The energy investments segment's EBIT was down $9 million primarily due to the loss of EBIT contributions as the result of the sale in 2005 of certain assets that were originally acquired with the 2004 acquisition of NUI.

Our operating margin increased $47 million or 4% from 2005. The following table indicates the significant changes in our operating margin:

In millions

Operating margin for 2005	$	1,092
Net change in the fair value of hedges at wholesale services		60
Increased operating margins at retail energy operations		16
Increased wholesale services commercial activities		5
Wholesale services inventory LOCOM adjustments (net of hedging recoveries)		(18)
Retail energy operations inventory LOCOM adjustments		(6)
Lower operating margins at distribution operations utilities		(7)
Loss of margin from energy investment assets sold in 2005		(9)
Other		6
Operating margin for 2006	$	1,139

Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with both weather-related seasonal fluctuations and changing commodity prices. In addition, because these economic hedges are generally not designated for hedge accounting treatment, 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 margin or our other comprehensive income (OCI) for those derivative instruments that qualify and are designated as accounting hedges.

Forward NYMEX prices decreased during 2006, especially during the third and fourth quarters. This resulted in the wholesale services segment recognizing $41 million of storage hedge gains in 2006, compared to the recognition of $7 million of storage hedge losses in 2005. In addition, wholesale services recognized $12 million in gains associated with the financial instruments used to hedge its transportation capacity. Consequently, wholesale services experienced a net change of $60 million from its hedging activities for 2006 compared to 2005.

The results of the wholesale services segment also reflect improved commercial activities of approximately $5 million. Sequent was able to capture higher seasonal storage margins in 2006 and additional operating margin opportunities brought on by higher temperatures during the late summer months. This offset the lower operating margins that resulted from milder weather earlier in the year.

As a result of decreasing NYMEX prices, the wholesale services segment evaluated the weighted average cost of its natural gas inventory and recorded LOCOM adjustments totaling $43 million during 2006; however, as inventory was physically withdrawn from storage during the year, $22 million of the 2006 adjustments were recovered and reflected in 2006 operating revenues when the original economic results were realized as the related hedging derivatives were settled.

We experienced increased operating margins at our retail energy operations segment of $10 million driven by improved retail margins of $6 million and slightly higher storage and commercial margins of $4 million. Storage and commercial margins were driven by improved optimization of storage and transportation assets and effective commodity risk management, including net gains on weather derivatives offset by a $6 million adjustment in 2006 to reduce inventory to market for which no LOCOM adjustment was recorded in 2005. Retail operating margins increased due to improved retail price spreads and an increase in the average number of customers offset by lower customer consumption due to weather that was more than 10% warmer than the previous year and lower late payment fees of $1 million due to an increase in the number of customers utilizing payment arrangements.

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Operating margin for the distribution operations segment decreased $7 million primarily from warmer weather affecting customer usage and from our exiting the New Jersey and Florida appliance businesses. The margin at Elizabethtown Gas decreased $3 million with 18% warmer weather than in 2005. Virginia Natural Gas' margin decreased $4 million with 17% warmer weather, and the margin at Florida City Gas decreased $2 million with 16% warmer weather. Further, our exiting from the New Jersey and Florida appliance businesses reduced margin by $3 million. This margin reduction was partially offset by increased margin at Atlanta Gas Light of $6 million primarily from gas storage carrying costs from higher average inventory balances and pipeline replacement program revenues from the continuing expenditures under the program.

Our energy investments segment operating margin decreased $4 million due to the loss of contributions from certain assets we acquired with the 2004 acquisition of NUI, but later sold in 2005.

Our operating expenses increased $1 million or 0.2% from the same period in 2005. The following table sets forth the significant components of operating expenses:

In millions	
Operating expenses for 2005	$ 650
Increased depreciation and amortization	5
Increased payroll, incentive compensation and corporate overhead allocated costs at wholesale services	7
Increased bad debt expenses at retail energy operations and distribution operations	4
Lower expenses resulting from energy investment assets sold in 2005	(8)
Lower expenses at distribution operations related to workforce and facilities restructurings in 2005 and 2006	(15)
Other	8
Operating expenses for 2006	$ 651

The wholesale services segment recorded $7 million of additional costs associated with payroll due to an increased number of employees to support growth and increased incentive compensation, which is generally based on Sequent's operating performance. Bad debt expense for 2006 increased over 2005 primarily in our retail energy operations segment. The retail energy operation's bad debt for 2006 was $13 million, a $3 million increase from the same period in 2005, driven by an increase in the number of accounts receivable balances past due more than 60 days due to higher natural gas bills.

These increases were offset by $15 million in lower costs primarily related to a 2005 restructuring at the distribution operations segment, as a result of a reduction in the workforce and elimination of unnecessary facilities following the 2004 acquisition of NUI. An additional $8 million decrease in operating expenses was related to the operation of assets, primarily in the energy investments segment, that were originally acquired in the 2004 acquisition of NUI and later sold in 2005.

Interest expense for 2006 increased by $14 million or 13% as compared to 2005. As indicated in the following table, higher short-term interest rates and higher debt outstanding combined to increase our interest expense in 2006 relative to the previous year. The increase of $200 million in average debt outstanding for 2006 compared to 2005 was due to additional debt incurred as a result of higher working capital requirements.

In millions	**2006**	**2005**
Total interest expense	$ 123	$ 109

Average debt outstanding (1)	2,023	1,823
Average interest rate	6.1%	6.0%

(1) Daily average of all outstanding debt.

Based on $733 million of variable-rate debt, which includes $527 million of variable-rate short-term debt, $100 million of variable-rate senior notes and $106 million of variable-rate gas facility revenue bonds outstanding at December 31, 2006, a 100 basis point change in market interest rates from 5% to 6% would result in an increase in annual pretax interest expense of $7 million.

The increase in income tax expense of $12 million or 10% for 2006 compared to 2005 reflected additional income taxes primarily due to higher corporate earnings year over year. We expect our effective tax rate for the year ending December 31, 2007, to be similar to the effective rate for the year ended December 31, 2006.

2005 compared to 2004 Consolidated EBIT for 2005 increased by $105 million or 33% from the previous year, of which $56 million related to EBIT contributions from the 2004 acquisitions of NUI and Jefferson Island Storage & Hub, LLC (Jefferson Island) and from Pivotal Propane of Virginia, Inc. (Pivotal Propane) which became operational in 2005. The increase further reflected increased contributions of $8 million from Atlanta Gas Light in distribution operations, $11 million from retail energy operations and $3 million from AGL Networks, LLC (AGL Networks) in energy investments. Wholesale services' EBIT increased $25 million primarily due to increased operating margins partially offset by higher operating expenses. Corporate segment results improved by $5 million compared to 2004, primarily due to merger and acquisition-related costs incurred in 2004 but not in 2005.

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Our operating margin in 2005 increased $255 million or 30% from 2004. The following table indicates the significant changes in our operating margin:

In millions		
Operating margin in 2004	$	837
Increased operating margin at distribution operations from acquired utilities		167
Increased wholesale services commercial activities		53
Increased operating margins at retail energy operations		14
Increased operating margins at Jefferson Island		13
Operating margin from energy investment assets acquired from NUI Corp.		8
Increased operating margin at distribution operations, primarily Atlanta Gas Light		7
Increased operating margins at Pivotal Propane and AGL Networks		7
Inventory LOCOM adjustments at wholesale services		(2)
Net change in the fair value of hedges at wholesale services		(12)
Operating margin in 2005	$	1,092

The increase primarily reflects the NUI and Jefferson Island acquisitions and completion of the Pivotal Propane facility in Virginia, as well as improved margins at SouthStar, Sequent and AGL Networks. Excluding the addition of the NUI utilities, distribution operations' margins improved by $7 million mainly as a result of higher pipeline replacement revenues and additional carrying costs charged to Marketers for gas storage. Retail energy operations' margins increased $14 million, due primarily to higher commodity margins. Wholesale services' operating margin increased $39 million year over year, primarily due to significant market volatility following the hurricane activity during the third quarter and the continuing volatile market conditions during the fourth quarter of 2005. Energy investments' margins were up $27 million, primarily as a result of the acquisition of Jefferson Island that contributed $13 million, contributions from NUI's nonutility businesses of $8 million, contribution from Pivotal Propane of $3 million and improved operating margin at AGL Networks of $4 million.

Our operating expenses increased $145 million or 29% from 2004. The following table sets forth the significant changes in our operating expenses:

In millions		
Operating expenses in 2004	$	505
Operating expenses at distribution operations from NUI utilities acquired December 2004		125
Increased operating expenses at wholesale services, primarily payroll, incentive compensation and depreciation		13
Operating expenses at energy investments from NUI acquired assets		8
Operating expenses at Jefferson Island		3
Operating expenses at energy investments from Pivotal Propane		3
Other		(7)
Operating expenses in 2005	$	650

The increase was primarily a result of $124 million in higher expenses at distribution operations due to the addition of NUI. In addition, operating expenses at energy investments increased $15 million primarily due to the addition of Jefferson Island, the NUI nonutility assets and Pivotal Propane. Operating expenses at wholesale services increased $13 million due to increased payroll and employee incentive compensation costs resulting from its operational and financial growth and depreciation on a trading and risk management system placed in service during 2004. The increased operating expenses were offset by lower corporate operating expenses primarily due to prior-year costs incurred with merger and acquisition activities.

Interest expense for 2005 increased by $38 million or 54% as compared to 2004. As indicated in the table below, higher short-term interest rates and higher average debt outstanding combined to increase our interest expense in 2005 relative to the previous year. The increase of $549 million in average debt outstanding for 2005 was due to additional debt incurred as a result of the acquisitions of NUI and Jefferson Island and higher working capital requirements as a result of higher natural gas prices.

In millions	**2005**	**2004**
Total interest expense	$ 109	$ 71
Average debt outstanding (1)	1,823	1,274
Average interest rate	6.0%	5.6%

(1) Daily average of all outstanding debt.

The increase in income tax expense of $27 million or 30% for 2005 compared to 2004 reflected additional income taxes of $25 million due to higher corporate earnings year over year and $2 million due to a slightly higher effective tax rate of 38% for 2005 as compared to 37% in 2004.

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Distribution Operations

Distribution operations includes our six natural gas local distribution utility companies that construct, manage and maintain intrastate natural gas pipelines and distribution facilities and serve more than 2.2 million end-use customers.

Atlanta Gas Light This natural gas local distribution utility operates distribution systems and related facilities throughout Georgia serving approximately 1.5 million end-use customers. Atlanta Gas Light customer counts are approximately 94% residential and 6% commercial or industrial. Atlanta Gas Light is regulated by the Georgia Commission and its rates are frozen until 2010.

Atlanta Gas Light's natural gas market was deregulated in 1997 with Georgia's Natural Gas Competition and Deregulation Act (Deregulation Act). Prior to this act, Atlanta Gas Light was the supplier and seller of natural gas to its customers. Today, Marketers—that is, marketers who are certificated by the Georgia Commission to sell retail natural gas in Georgia on terms approved by the Georgia Commission — 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

Elizabethtown Gas This natural gas local distribution utility operates distribution systems and related facilities serving approximately 269,000 customers in central and northwestern New Jersey. Most Elizabethtown Gas customers are located in densely populated central New Jersey, where increases in the number of customers primarily result from conversions to gas heating from alternative forms of heating. In the northwestern region of the state, customer additions are driven primarily by new construction. Elizabethtown Gas customer counts are approximately 92% residential and 8% commercial or industrial. Elizabethtown Gas is regulated by the New Jersey Commission and its rates are frozen until 2010.

Virginia Natural Gas This natural gas local distribution utility operates distribution systems and related facilities serving approximately 264,000 customers in southeastern Virginia. Virginia Natural Gas customer counts are approximately 92% residential and 8% commercial or industrial. Virginia Natural Gas is regulated by the Virginia Commission and its rates are frozen until 2011 subject to the terms of its PBR plan.

Florida City Gas This natural gas local distribution utility operates distribution systems and related facilities serving approximately 104,000 customers in central and southern Florida. Florida City Gas customers purchase gas primarily for heating water, drying clothes and cooking. Some customers, mainly in central Florida, also purchase gas to provide space heating during the winter season. Florida City Gas customer counts are approximately 94% residential and 6% commercial or industrial. Florida City Gas is regulated by the Florida Commission.

Chattanooga Gas This natural gas local distribution utility operates distribution systems and related facilities serving approximately 61,000 customers in the Chattanooga and Cleveland areas of southeastern Tennessee. Chattanooga Gas customer counts are approximately 86% residential and 14% commercial or industrial. Chattanooga Gas is regulated by the Tennessee Commission.

Elkton Gas This natural gas local distribution utility operates distribution systems and related facilities serving approximately 6,000 customers in Cecil County, Maryland. Elkton Gas customer counts are approximately 92% residential and 8% commercial or industrial. Elkton Gas is regulated by the Maryland Commission.

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The following table provides operational information for our five largest utilities. The daily capacity represents total system capability, and the storage capacity includes on-system LNG and propane volumes.

	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida City Gas	Chattanooga Gas
Operations					
2006 avg. customers (in thousands)	1,546	269	264	104	61
2005 avg. customers (in thousands)	1,545	266	261	103	61
2004 avg. customers (in thousands) (6)	1,533	263	256	103	60
Storage capacity (1)	48.4	13.0	9.6	-	3.6
Throughput -- 2006 (1)	211	46	33	9	15
Throughput -- 2005 (1)	232	59	36	10	16
Throughput -- 2004 (1) (6)	233	65	34	9	16
Peak storage capacity (1)	7.8	0.8	1.6	-	1.2
Miles of main (7)	30,284	3,030	5,235	3,207	1,521
Heating degree days -- 2006 (2)	2,466	4,110	2,869	696	2,898
2006 % warmer than 2005	(10%)	(18%)	(17%)	(16%)	(7 %)
Heating degree days -- 2005 (2)	2,726	5,017	3,465	829	3,115
2005 % colder than 2004	5%	2%	8%	3%	3 %
Heating degree days -- 2004 (2) (6)	2,589	4,918	3,214	802	3,010
Rates					
Last decision on change in rates	Jun. 2005	Nov. 2002	Oct. 1996	Feb. 2004	Dec. 2006
Authorized return on rate base (5)	8.53%	7.95%	9.24%	7.36%	7.43 %
Estimated 2006 return on rate base (3)	8.45%	7.83%	7.65%	7.41%	7.00 %
Authorized return on equity	10.9%	10.0%	10.9%	11.25%	10.2 %
Estimated 2006 return on equity (3)	10.73 %	9.40 %	8.49 %	10.67 %	9.01 %
Authorized rate base % of equity (4)	47.9 %	53.0 %	52.4 %	36.8 %	10.2 %
Rate base included in 2006 return on equity (in millions) (4)	$ 1,238	$ 417	$ 351	$ 120	$102

(1) In Bcf

(2) We measure effects of weather on our businesses using “degree days.” The measure of degree days for a given day is the mean daily temperature (average of the daily high and low temperature) and a baseline temperature of 65 degrees Fahrenheit. Heating degree days result when the mean daily temperature is less than the 65-degree baseline. Generally, increased heating degree days result in greater demand for gas on our distribution systems.

(3) Estimate based on principles consistent with utility ratemaking in each jurisdiction. Returns are not necessarily consistent with GAAP returns.

(4) Estimated based on 13-month average.

(5) The authorized return on rate base, return on equity, and percentage of equity reflected above were those authorized as of December 31, 2006. Effective January 1, 2007, Chattanooga Gas' authorized return on rate base, return on equity and percentage of equity are 7.89%, 10.2% and 44.8%, respectively, due to the results of its base rate case settled in December 2006.

(6) Includes amounts for the full year of 2004; however, we acquired these utilities in December 2004. The December 2004 end-use customers for Elizabethtown Gas was 266 and 103 for Florida City Gas, December 2004 distribution for Elizabethtown Gas was 8.2 and 0.9 for Florida City Gas; and December 2004 heating degree days for Elizabethtown Gas was 873 and 239 for Florida City Gas.

(7) Includes distribution and transmission main only.

Regulatory Environment Each utility operates subject to regulations provided by the state regulatory agency in its service territories with respect to rates charged to our customers 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 allow recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base generally consists of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service, net deferred income tax liabilities and certain other deductions. Our utilities are authorized to use a purchased gas adjustment (PGA) mechanism that allows them to automatically adjust their rates to reflect changes in the wholesale cost of natural gas and to ensure the utilities recover 100% of the costs incurred in purchasing gas for their customers. We continuously monitor the performance of our utilities to determine whether rates need to be further adjusted through a rate case filing.

Straight-Fixed-Variable Rates Atlanta Gas Light recognizes revenue under a straight-fixed-variable rate design whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges, however the Marketers bill these charges directly to their customers. This mechanism minimizes the seasonality of revenues since the monthly fixed charge is not volumetric and the monthly charge is not set to be directly weather dependent. 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.

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Weather Normalization The tariffs of Elizabethtown Gas, Virginia Natural Gas, and Chattanooga Gas contain WNA provisions that are designed to help stabilize operating margin 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. The WNA is most effective in a reasonable temperature range relative to normal weather using historical averages. For Elizabethtown Gas, the weather normalization provision was renewed in October 2004 and is based on a 20-year average of weather conditions.

Virginia Natural Gas received from the Virginia Commission approval of a weather normalization program in September 2002 as a two-year experiment involving the use of special rates. In September 2004, Virginia Natural Gas received approval from the Virginia Commission to extend the WNA program for an additional two years with certain modifications to the existing program. The modifications included removal of the commercial class of customers from the WNA program and the use of a rolling 30-year average to calculate the weather factor that is updated annually. The residential WNA program was made permanent by Virginia Commission order in September 2006.

Chattanooga Gas' base rates include a weather normalization provision that allows for revenue to be recognized based on a factor derived from average temperatures over a 30-year period, which offsets the impact of unusually cold or warm weather on its operating income.

Rate Settlement Agreements On July 24, 2006, the Virginia Commission issued an order approving Virginia Natural Gas' PBR plan with modifications. Under the PBR rate plan, Virginia Natural Gas' rates were frozen as an incentive for it to promote cost containment, productivity and rate stability without traditional rate proceedings that set rates based on investment, return and cost of service. These modifications include a requirement to construct and report on the progress of a pipeline connecting Virginia Natural Gas' northern and southern systems and reporting requirements to monitor compliance with the terms of the PBR plan. Virginia Natural Gas accepted the terms of the PBR plan as modified by the Virginia Commission in August 2006. The modified PBR plan was effective August 1, 2006 with base rates frozen at current levels for five years. The estimated cost to construct the pipeline is between $48 million and $60 million, and the pipeline is expected to be completed in 2009.

On June 30, 2006, we filed a general rate case with the Tennessee Commission seeking approximately $6 million in increased annual base rates to cover the rising cost of service at Chattanooga Gas. Our rate case included a proposal for comprehensive rate design, including an energy conservation program (ECP) and a conservation and usage adjustment (CUA). The ECP would provide incentives for customers to reduce their natural gas consumption by offering rebates for more energy-efficient appliances and to help customers better manage their energy costs. The CUA is designed to mitigate the financial impact on Chattanooga Gas of expected increased energy conservation by customers through rate adjustments.

The Tennessee Commission divided the case into two phases: one phase to examine the revenue requirements and traditional rate design issues and a second phase to review the CUA and ECP. Approximately $5 million of our base rate request was related to the revenue requirement. In December 2006, the Tennessee Commission approved a settlement agreement between Chattanooga Gas, the Consumer Advocate and Protection Division of the Attorney General's Office (Consumer Advocate) and the Chattanooga Manufacturers Association settling the revenue requirements and traditional rate design issues of the case. The settlement agreement was effective January 1, 2007 and provides for a base rate increase of approximately $3 million of which $2 million will be an increase in operating margin and the remaining will be a $1 million shift from WNA to base rates and have no overall impact on operating margin.

The settlement agreement establishes and authorized return on equity of 10.2% for Chattanooga Gas, resulting in an overall authorized rate of return of 7.89%. Prior to the settlement agreement, Chattanooga Gas' authorized return on equity was 10.2% and its overall authorized rate of return was set at 7.43%. The second phase of the case is scheduled to begin in February 2007 with a final ruling expected by September 30, 2007.

Customer Demand Our distribution operations businesses face competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. Our principal competition relates to electric utilities and oil and propane providers serving the residential and commercial markets throughout our service areas primarily through the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the prices for competing sources of energy and the desirability of natural gas heating versus alternative heating sources.

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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 housing starts

In some of our service areas, net growth continues to be slowed due to the number of customers who leave our systems because of higher natural gas prices and competition from alternative fuel sources, including incentives offered by the local electric utilities to switch to electric heat alternatives.

We expect customer growth to improve in the future through our efforts to obtain new customers and retain existing customers. These efforts include working to add residential customers, multifamily complexes and high-value commercial customers that use natural gas for purposes other than space heating. In addition, we partner with numerous entities to market the benefits of gas appliances and to identify potential retention options early in the process for those customers who might consider converting to alternative fuels.

Collective Bargaining Agreements In 2006, a collective bargaining agreement representing approximately 300 Atlanta Gas Light employees by Teamsters Local 528 was not renewed. As a result, these employees are no longer represented by a bargaining unit and now fall under our standard human resources pay and benefit plans and policies. In January 2007, a majority of Chattanooga Gas' bargaining unit employees submitted a petition to Chattanooga Gas requesting the decertification of the Utility Workers Union of America, Local 461, as their bargaining representative. Based on that majority showing, Chattanooga Gas filed a petition with the National Labor Relations Board requesting that the Board conduct a decertification election.The decertification election is currently scheduled to take place on February 16, 2007. The following table provides information about the collective bargaining agreements to which our natural gas local distribution utilities are parties:

	Affiliated subsidiary	**Approximate # of employees**	**Date of contract expiration**
Communications Workers of America (Local No. 1023)	Elizabethtown Gas	8	April 2007
Utility Workers Union of America (Local No. 461)	Chattanooga Gas	21	April 2007
International Union of Operating Engineers (Local No. 474)	Atlanta Gas Light	26	August 2007
Teamsters (Local Nos. 769 and 385)	Florida City Gas	50	March 2008
Utility Workers Union of America (Local No. 424)	Elizabethtown Gas	160	November 2009
International Brotherhood of Electrical Workers (Local No. 50)	Virginia Natural Gas	141	May 2010

Total	406

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Results of Operations The following table presents results of operations for distribution operations for the years ended December 31, 2006, 2005 and 2004.

In millions	**2006**	**2005**	**2004**
Operating revenues	$ 1,624	$ 1,753	$ 1,111
Cost of gas	817	939	471
Operating margin (1)	807	814	640
Operating expenses	499	518	394
Operating income	308	296	246
Other income	2	3	1
EBIT (1)	$ 310	$ 299	$ 247
Metrics (2)			
Average end-use customers (in thousands)	2,250	2,242	1,880
Operation and maintenance expenses per customer	$ 156	$ 166	$ 152
EBIT per customer	$ 138	$ 133	$ 131

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations - AGL Resources."

(2) 2004 metrics include only December for Florida City Gas, Elizabethtown Gas and Elkton Gas.

2006 compared to 2005 EBIT increased $11 million or 4% in 2006 reflecting a decrease in operating expenses of $19 million, partially offset by decreased operating margin of $7 million.

The operating margin decrease of $7 million or 1% in 2006 was primarily the result of lower usage resulting from customer conservation and warmer weather. Operating margins decreased $4 million at Virginia Natural Gas, $3 million at Elizabethtown Gas and $2 million at Florida City Gas. Also contributing to the decrease was a $3 million decrease due to our exit from the New Jersey and Florida appliance business operations in 2005. These decreases were offset by a net increase in Atlanta Gas Light's operating margin of $6 million consisting of $5 million in gas storage carrying costs and $2 million in pipeline replacement program (PRP) revenues, offset primarily by $2 million as a result of the effect of the Georgia Commission's June 2005 Rate Order.

Operating expenses decreased $19 million or 4% in 2006 compared to the same period in 2005, primarily due to lower compensation and facilities expense of $10 million, resulting from a workforce and facilities restructuring in 2005, $5 million of reduced outside services and $3 million in lower costs due to our exiting the appliance businesses acquired with our purchase of NUI. These decreases were offset by a $1 million increase in bad debt expense primarily at Elizabethtown Gas due to higher gas prices in 2006. Operating expenses also reflect a $2 million net gain compared to 2005 primarily due to the sale of properties in Georgia in 2006.

2005 compared to 2004 EBIT increased $52 million or 21% reflecting an increase in operating margin of $174 million, partially offset by increased operating expenses of $124 million. The businesses acquired from NUI on November 30, 2004 contributed approximately $50 million of EBIT in 2005 compared to $7 million in 2004. This was due to the inclusion of the full-year NUI results in 2005 as compared to the inclusion of one month in 2004.

The $174 million or 27% increase in operating margin was primarily due to the addition of NUI's operations, which contributed $167 million. The remainder was primarily due to $8 million of higher operating margin at Atlanta Gas Light. The increase at Atlanta Gas Light resulted primarily from higher PRP revenues of $6 million and higher revenue of $3 million from additional carrying charges to Marketers for gas stored, primarily due to higher gas prices. Atlanta Gas Light also had approximately $3 million of increased operating margin from net customer growth, which offset a $3 million decrease in operating revenues that resulted from the June 2005 Settlement Agreement with the Georgia Commission. Operating margin at Virginia Natural Gas and Chattanooga Gas remained relatively flat compared to 2004.

The $124 million or 31% increase in operating expenses primarily reflected the addition of NUI's operations which increased operating expenses by $125 million.

Retail Energy Operations

Our retail energy operations segment consists of SouthStar, a joint venture owned 70% by our subsidiary, Georgia Natural Gas Company, and 30% by Piedmont Natural Gas (Piedmont). SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia as well as to commercial and industrial customers in Tennessee, North Carolina, South Carolina and Alabama. During 2006, SouthStar entered into agreements with customers in Ohio and Florida to supply natural gas starting in the fourth quarter of 2006.

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The SouthStar executive committee, which acts as the governing board, is comprised of six members, three representatives from AGL Resources and three from Piedmont. Under the joint venture agreement, all significant management decisions require the unanimous approval of the SouthStar executive committee; accordingly, our 70% financial interest is considered to be noncontrolling. Although our ownership interest in the SouthStar partnership is 70%, SouthStar's earnings are allocated 75% to us and 25% to Piedmont, under an amended and restated joint venture agreement executed in March 2004. Earnings related to customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

Competition SouthStar competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. Based on its market share, SouthStar is the largest Marketer of natural gas in Georgia, with average customers over the last three years in excess of 530,000.

In addition, similar to distribution operations, SouthStar faces competition based on customer preferences for natural gas compared to other energy products and the comparative prices of those products. SouthStar's principal competition for other non-natural gas energy products relates to electric utilities and the potential displacement or replacement of natural gas appliances with electric appliances. This competition with other energy products has been exacerbated by price volatility in the wholesale natural gas commodity market and related significant increases in the cost of natural gas billed to SouthStar's customers, especially during the fourth quarter of 2005 and the first and second quarters of 2006.

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

The combination of these two retail price components is evaluated by SouthStar 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 margins are impacted by seasonal weather, natural gas prices, customer growth and SouthStar's related market share in Georgia, which has historically been approximately 35%. 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 customers.

The third way SouthStar generates 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 margins. SouthStar is allocated storage and pipeline capacity that is used to supply gas to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices using natural gas storage transactions to capture 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.

SouthStar accounts for its natural gas inventories at the lower of weighted average cost or current market price. SouthStar evaluates the weighted average cost of its natural gas inventories against market prices and determines whether any declines in market prices below the weighted average cost are other than temporary. For declines considered to be other than temporary, SouthStar records adjustments to cost of gas in our consolidated statement of income to reduce the weighted average cost of the natural gas inventory to the current market price. As of December

31, 2006, SouthStar recorded a LOCOM adjustment of $6 million. SouthStar did not record a LOCOM adjustment in 2005 or 2004.

We have designated a portion of SouthStar's derivative transactions as cash flow hedges under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). We record derivative gains or losses arising from cash flow hedges in OCI and reclassify them into earnings in the same period as the underlying hedged item 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 SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to preserve margins in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under Emerging Issues Task Force (EITF) Issue No. 99-02, “Accounting for Weather Derivatives.” The weather derivative contracts contain settlement provisions based on cumulative heating degree days for the covered periods. In September 2006, SouthStar entered into weather derivatives (swaps and options) for the current winter heating season. During 2006, SouthStar recorded net gains on these weather derivatives of approximately $5 million. These gains were largely offset by a corresponding loss of operating margin due to the warm weather the hedge was designed to protect against.

Impact of Volatility in Natural Gas Prices SouthStar’s operating margin and EBIT from the sales of natural gas to retail customers were affected by lower average usage in part due to conservation and higher bad debt as a result of higher and more volatile natural gas prices during the 2005-2006 heating season. SouthStar was also affected when natural gas prices further declined at the end of 2006 resulting in a LOCOM adjustment to inventory.

SouthStar’s operating margin and EBIT associated with the optimization of storage and transportation assets and commodity risk management during 2006 were affected by the decline in wholesale natural gas prices. In 2005, natural gas prices were significantly higher in part due to gas supply disruptions brought on by hurricanes Katrina and Rita. For derivatives not designated as hedges under SFAS 133, SouthStar generally records fair value losses as natural gas prices decrease and fair value gains as natural gas prices increase.

SouthStar’s bad debt expense was $13 million for 2006, a $3 million increase from 2005. The increase in bad debt was impacted by an increase in the amount of accounts receivable balances past due more than 60 days and the expectation that a majority of these past due accounts will not be collected. In addition, $1 million of aged deposits were applied to SouthStar’s bad debt on a one-time basis in 2005. SouthStar entered into payment arrangements with these customers in an effort to help customers pay their higher natural gas bills during the 2005-2006 heating season. We expect that SouthStar’s collection efforts will continue to help mitigate the overall impact of bad debt expense as a percentage of operating revenues, which were 1.4% for the year ended December 31, 2006 compared to approximately 1.1% (excluding the one-time application of aged deposits) for the same period in 2005. We further believe that SouthStar’s higher credit-quality customer base mitigates our exposure to higher bad debt expenses.

SouthStar also has experienced lower average usage per customer during 2006, compared to the same period in 2005 due to a number of factors including warmer weather and the effects of customer conservation. Though these two factors have contributed to a $16 million unfavorable impact on operating margin, net of gains on weather derivatives, relative to wholesale prices and normalized temperatures. SouthStar achieved a net increase in operating margin of $10 million for 2006 compared to 2005.

Ohio Retail Market In August 2006, SouthStar was awarded the right to supply approximately a total of 10 Bcf of natural gas to customers of Dominion East Ohio (Dominion Ohio) through August 2008 (approximately 5 Bcf/year). As part of this agreement, SouthStar will manage supply, transportation and storage of natural gas on behalf of Dominion Ohio. While we do not expect the Dominion Ohio agreement to materially impact our results of operations, SouthStar’s entrance into the Ohio market is part of its continued growth strategy.

Results of Operations The following table presents results of operations for retail energy operations for the years ended December 31, 2006, 2005, and 2004.

In millions	**2006**	**2005**	**2004**
Operating revenues	$ 930	$ 996	$ 827
Cost of gas	774	850	695
Operating margin (1)	156	146	132

Operating expenses	68	61	62
Operating income	88	85	70
Other expense	(2)	-	-
Minority interest	(23)	(22)	(18)
EBIT (1)	$ 63	$ 63	$ 52
Metrics - Georgia Market			
Average customers (in thousands)	533	531	533
Market share in Georgia	35%	35%	36%
Natural gas volumes (Bcf)	38	44	45

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations - AGL Resources. "

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2006 compared to 2005 EBIT for 2006 was relatively flat as compared to 2005, driven by a $10 million increase in operating margin which was offset by a $7 million increase in operating expenses, a $2 million increase in other expense and a $1 million increase in minority interest due to the slightly higher operating income.

Operating margin increased by $10 million or 7% driven by improved retail operating margins of $6 million and higher storage margin gains of $4 million. Retail operating margins increased due to improved retail spreads and an increase of approximately 2,000 average customers in 2006 compared to 2005, offset by lower customer consumption due to weather that was approximately 10% warmer than 2005 and conservation. Late payment fees were $1 million lower in 2006 as compared to 2005 due to more customers being on payment arrangements in 2006. Additionally, retail operating margins decreased compared to 2005 due to higher interruptible margins in 2005 driven by peaking sales during curtailments. Storage margins were driven by improved optimization of storage and transportation assets and effective commodity risk management including net gains on weather derivatives. Storage operating margins were impacted by an adjustment in 2006 of $6 million to reduce inventory to market for which no LOCOM adjustment was recorded in 2005.

Operating expenses increased $7 million or 11% primarily due to higher bad debt expense of $3 million, increased depreciation of $1 million due to the implementation of system enhancements, higher outside service costs of $1 million principally driven by the current-year implementation of a new energy trading and risk management (ETRM) system and $1 million from increases in other general corporate overhead costs.

The retail energy operations segment made a $2 million charitable contribution in 2006. Minority interest increased $1 million as a result of increased operating income in 2006 compared to 2005.

2005 compared to 2004 The $11 million or 21% increase in EBIT for 2005 was driven by a $14 million increase in operating margin and a $1 million decrease in total operating expenses, offset by a $4 million increase in minority interest due to higher earnings.

The $14 million or 11% increase in operating margin was primarily the result of higher commodity margins and positive margin captured with SouthStar's storage assets, offset by lower customer usage and lower late payment fees relative to 2004.

There was a slight decrease in operating expenses in 2005 compared to 2004. The decrease was primarily due to $1 million in lower bad debt expense resulting from ongoing collection process improvements. Minority interest increased $4 million or 22% as a direct result of increased operating income in 2005 compared to 2004.

Wholesale Services

Wholesale services consists of Sequent, our subsidiary involved in asset management, transportation, storage, producer and peaking services and wholesale marketing. Our asset management business focuses on capturing economic value from idle or underutilized natural gas assets, which are typically amassed by companies via investments in or contractual rights to natural gas transportation and storage assets. Margin is typically created in this business by participating in transactions that balance the needs of varying markets and time horizons.

Sequent provides customers with natural gas from the major producing regions and market hubs primarily in the eastern and mid-continental United States. Sequent purchases 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. In 2006, Sequent entered into an agreement which should facilitate the expansion of its operations into the western United States and Canada and plans to pursue additional opportunities in these regions during 2007. Sequent continues to work on projects and transactions to extend its operating territory and is entering into agreements of longer duration, as well as evaluating opportunities to expand its business focus and models.

Seasonality Fixed cost commitments are generally incurred evenly over the year, while margins generated through the use of the assets are generally greatest in the winter heating season and occasionally in the summer due to peak usage by power generators in meeting air-conditioning load. This increases the seasonality of Sequent's business, generally resulting in higher margins in the first and fourth quarters.

Competition Sequent competes for asset management business with other energy wholesalers, often through a competitive bidding process. There has been significant consolidation of energy wholesale operations, particularly among major gas producers. Financial institutions have also entered the marketplace. As a result, energy wholesalers have become increasingly willing to place bids for asset management transactions that are priced to capture market share. We expect this trend to continue in the near term, which could result in downward pressure on the volume of transactions and the related margins available in this portion of Sequent's business.

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Asset Management Transactions Our asset management customers include our own utilities, nonaffiliated utilities, municipal utilities and large industrial customers. These customers must independently contract for transportation and storage capacity to meet their demands, and they typically contract for this capacity on a 365-day basis even though they may only need a portion of the capacity to meet their peak demands. Sequent enters into agreements with these customers, either through contract assignment or agency arrangement, whereby Sequent uses the customers' rights to transportation and storage capacity during periods when customers do not need it. Sequent captures margin by optimizing the purchase, transportation, storage and sale of natural gas, and Sequent typically either shares profits with customers or pays them a fee for using their assets.

The following table provides additional information on Sequent's asset management agreements with its affiliated utilities.

In millions	Expiration date	Timing of payment	Type of fee structure	% Shared or annual fee	Profit sharing / fees payments 2006	2005	2004
Elkton Gas	Mar 2008	Monthly	Fixed-fee	(A)	$ -	$ -	$ -
Chattanooga Gas	Mar 2008	Annually	Profit -sharing	50%	4	2	1
Atlanta Gas Light	Mar 2008	Semi-Annually	Profit -sharing	60%	6	4	4
Elizabethtown Gas	Mar 2008	Monthly	Fixed -fee	$ 4	4	-	-
Florida City Gas	Mar 2008	Annually	Profit -sharing	50%	-	-	-
Virginia Natural Gas	Mar 2009	Annually	Profit -sharing	(B)	2	5	3
Total					$ 16	$ 11	$ 8

(A) Annual fixed fee is less than $1 million.

(B) Profit sharing is based on a tiered sharing structure.

In January 2006, the Georgia Commission extended the asset management agreement between Sequent and Atlanta Gas Light for two additional years. In addition, Sequent's asset management agreements with Chattanooga Gas and Elkton Gas were extended for an additional year through March 2008.

Transportation Transactions Sequent contracts for natural gas transportation capacity and participates in transactions that manage the natural gas commodity and transportation costs to result in 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 least-cost alternatives to serve the various markets. This enables Sequent to capture geographic pricing differences across these various markets as delivered gas prices change.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results. During 2006, Sequent reported gains of $12 million associated with transportation capacity hedges. The majority of this amount will be reversed during 2007 as the positions are settled. Sequent did not report any significant gains or losses on these types of hedges during 2005 or 2004.

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, principally in the Gulf Coast region. Sequent provides producers with certain logistical and risk management services that offer producers attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows Sequent to provide markets to producers who seek a reliable outlet for their natural gas production.

Peaking Services Sequent generates operating margin through, among other things, the sale of peaking services, which includes receiving a fee from affiliated and nonaffiliated customers that guarantees those customers will receive gas under peak conditions. Sequent incurs costs to support its obligations under these agreements, which are reduced in whole or in part as the matching obligations expire. Sequent will continue to seek new peaking transactions as well as work toward extending those that are set to expire.

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Credit Rating 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 with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting with these counterparties would be impaired. If at December 31, 2006 our credit ratings had been downgraded to non-investment grade, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $10 million.

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 SFAS 133. 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 as required under the EITF Issue No. 02-03, "Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, 'Accounting for Contracts Involved in Energy Trading and Risk Management Activities'" (EITF 02-03) rescission of EITF 98-10, unless they are derivatives that must be recorded at fair value under SFAS 133.

As shown in the table below, Sequent 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 $132 million during 2006, $30 million of unrealized losses during 2005 and unrealized gains of $22 million during 2004. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2006, 2005 and 2004 and provide details of the net fair value of contracts outstanding as of December 31, 2006.

In millions	**2006**	**2005**	**2004**
Net fair value of contracts outstanding at beginning of period	$ (13)	$ 17	$ (5)
Contracts realized or otherwise settled during period	17	(47)	11
Change in net fair value of contract gains	115	17	11
Net fair value of new contracts entered into during period	-	-	-
Net fair value of contracts outstanding at end of period	119	(13)	17
Less net fair value of contracts outstanding at beginning of period	(13)	17	(5)
Unrealized gain (loss) related to changes in the fair value of derivative instruments	$ 132	$ (30)	$ 22

The sources of Sequent's net fair value at December 31, 2006, are as follows. The "prices actively quoted" category represents Sequent's positions in natural gas, which are valued exclusively using NYMEX futures prices. "Prices provided by other external sources" are basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Sequent's basis spreads are primarily based on quotes obtained either through electronic trading platforms or directly from brokers.

In millions	**Prices actively quoted**	**Prices provided by other external sources**
Mature through 2007	$ 21	$ 80
Mature 2008 - 2009	6	8
Mature 2010 - 2012	-	2
Mature after 2012	-	2
Total net fair value	$ 27	$ 92

Mark-to-Market Versus Lower of Average Cost or Market 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 could receive in the future. Sequent attempts to mitigate substantially all of the commodity price risk associated with its storage portfolio. Sequent uses derivative instruments to reduce the risk associated with future changes in the price of natural gas. Sequent sells NYMEX futures contracts or other over-the-counter derivatives in forward months to substantially lock in the profit margin it will ultimately realize when the stored gas is actually sold.

We view Sequent's trading margins from two perspectives. First, our commercial decisions are based on economic value, which is defined as the locked-in gain to be realized in the statement of income at the time the physical gas is withdrawn from storage and ultimately sold and the derivative instrument used to hedge natural gas price risk on that physical storage is settled. Second is the GAAP reported value both prior to and at the point of physical withdrawal. The GAAP amount is impacted by the process of accounting for the financial hedging instruments in interim periods at fair value between the time the gas is injected into storage and when it is ultimately withdrawn and the 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 characterized as unrealized gains or losses.

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Natural gas stored in inventory is accounted for 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 profit margin is essentially unchanged from the date the transactions were consummated. 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. During most of 2006, Sequent's reported results were positively impacted by decreases in forward NYMEX prices which resulted in the recognition of unrealized gains. In contrast, during most of 2005, Sequent's reported results were negatively impacted by increases in forward NYMEX prices which resulted in the recognition of unrealized losses, although to a lesser extent. During 2004, the reported results were not as significantly affected by changes in forward NYMEX prices. As a result, unrealized gains during 2006 had a positive impact on the favorable variance between 2006 and 2005 and unrealized losses during 2005 had a negative impact on the favorable variance between 2005 and 2004.

Storage Inventory Outlook The following graph presents the NYMEX forward natural gas prices as of December 31, 2005, September 30, 2006, and December 31, 2006 for the period of January 2007 through March 2008, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period.

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Sequent's expected withdrawals from physical salt dome and reservoir storage are presented in the table below along with the expected gross margin. Sequent's expected gross margin is net of the impact of regulatory sharing and reflects the amounts that it would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2006. Sequent's storage inventory is hedged with futures, and as shown below, the NYMEX short positions are equal to the physical long positions, which results in an overall locked-in margin, timing notwithstanding. Sequent's physical salt dome and reservoir volumes are presented in NYMEX equivalent contract units of 10,000 million British thermal units (MMBtu).

	Q1 2007	Q2 2007	Q3 2007	Q4 2007	Q1 2008	Total
Salt dome	412	-	-	-	7	419
Reservoir	850	1	-	96	116	1,063
Total volumes	1,262	1	-	96	123	1,482
Expected gross margin *(in millions)*	$ 9	$ -	$ -	$ 4	$ 5	$ 18

As of December 31, 2006, the weighted average cost of natural gas in inventory was $5.52 for physical salt dome storage and $5.18 for physical reservoir storage. These costs reflect adjustments that were recorded at the end of each quarter in 2006 in order to reduce the value of Sequent's natural gas inventory to market value at certain locations. Sequent reduced the inventory value by $9 million after regulatory sharing for the quarter ended December 31 and by $43 million for the year ended December 31, 2006. These adjustments negatively impacted Sequent's reported earnings. However, as the carrying value of the inventory was reduced, the expected gross margin in the table above increased by an equal and offsetting amount. Sequent recovered $22 million of the aggregate $43 million of gross margin reductions during 2006 and expects to recover the majority of the remainder during the first quarter of 2007, as both the inventory is withdrawn from storage and sold and the hedging instruments in place to lock in the original margins on the storage transactions are settled and recorded in our earnings.

Park and Loan Transactions Sequent routinely enters into park and loan transactions with various pipelines which allow it 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 traditional reservoir and salt dome storage transactions are evaluated and managed.

During the spring and summer months of 2006, natural gas prices were significantly lower than the futures prices for the upcoming winter months. As a result, Sequent has entered into transactions to park natural gas with the pipelines during the summer and receive the natural gas back during the winter.

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.

Although Sequent's quarterly results were modestly impacted by unrealized hedge losses during 2006, on an annual basis Sequent did not report any significant gains or losses on park and loan hedges during 2006, 2005, or 2004.

Results of Operations The following table presents results of operations for wholesale services for the years ended December 31, 2006, 2005, and 2004.

In millions	**2006**	**2005**	**2004**

Operating revenues	$ 182	$ 95	$ 54
Cost of sales	43	3	1
Operating margin (1)	139	92	53
Operating expenses	49	42	29
Operating income	90	50	24
Other expenses	-	(1)	-
EBIT (1)	$ 90	$ 49	$ 24
Metrics			
Physical sales volumes (Bcf / day)	2.20	2.17	2.10

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations - AGL Resources."

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The following table indicates the significant changes in operating margin for the years ended December 31, 2006, 2005 and 2004:

In millions	**2006**	**2005**	**2004**
Gain (loss) on storage hedges	$ 41	$ (7)	$ 5
Gain on transportation hedges	12	-	-
Commercial activity	107	102	49
Inventory LOCOM, net of hedging recoveries	(21)	(3)	(1)
Operating margin	$ 139	$ 92	$ 53

2006 compared to 2005 The increase in EBIT of $41 million or 84% in 2006 compared to 2005 was primarily due to an increase in operating margin of $47 million partially offset by an increase in operating expenses of $7 million.

Sequent’s operating margin increased by $47 million or 51% primarily due to improved commercial opportunities associated with larger seasonal storage spreads during the first half of 2006 and above average temperatures during the late summer months. These conditions offset the impacts of mild weather during the winter and early summer and the lower level of market volatility that we experienced compared to the hurricane activity in the Gulf of Mexico in 2005.

Additionally, the 2006 reported results were positively impacted by forward NYMEX prices moving downward and the narrowing of future seasonal spreads which resulted in the recognition of $41 million of gains on Sequent’s economic storage hedges in contrast to the prior period when forward prices increased and resulted in the recognition of $7 million of hedge losses. During 2006, Sequent also recognized $12 million in gains associated with financial instruments used to hedge its transportation capacity. There were no significant gains or losses associated with transportation hedges recognized in the prior period.

The positive impact from the price movements in 2006 was partially offset by LOCOM adjustments that Sequent recorded at certain storage locations during the year in order to reduce the carrying value of its natural gas inventory to current market prices. In 2006, Sequent recorded a total of $43 million in LOCOM adjustments; however $22 million of the adjustments were recovered during the period as the affected inventory was withdrawn from storage and sold and the hedging instruments in place to lock in the original margins on the storage transactions were settled. In 2005, Sequent recorded LOCOM adjustments of $3 million.

Operating expenses increased by $7 million or 17% primarily due to higher costs associated with an increase in the number of employees to support Sequent’s growth and additional incentive compensation costs directly related to stronger financial performance in 2006, as well as a higher percentage of corporate overhead costs than in 2005, primarily due to Sequent’s growth. The increased expenses were partially offset by lower costs associated with outside services and other expenses.

2005 compared to 2004 The increase in EBIT of $25 million or 104% in 2005 compared to 2004 was primarily due to an increase in operating margin of $39 million partially offset by an increase in operating expenses of $13 million.

Sequent’s operating margin increased by $39 million or 74% primarily due to the significant effects of the Gulf Coast hurricanes during the third quarter of 2005 and lingering market disruptions and price volatility throughout the fourth quarter. For the first nine months of the year, reported operating margins were similar to that of the prior year, with quarterly decreases being offset by quarterly increases. However, during the third quarter of 2005, while Sequent created substantial economic value by serving its customers during the storms, the reported operating margin was negatively impacted by accounting losses associated with storage hedges as a result of increases in forward NYMEX prices of approximately $6 per MMBtu. During the fourth quarter, natural gas prices continued to be volatile in the aftermath of the hurricanes and Sequent was able to further optimize its storage and transportation positions at levels in excess of the prior year. In addition, previously reported hedge losses were partially recovered during the fourth quarter as NYMEX prices decreased approximately $3 per MMBtu.

Operating expenses increased by $13 million or 45% due to additional payroll associated with increased headcount and increased employee incentive compensation costs driven by Sequent’s operational and financial growth and depreciation expense in connection with a new ETRM system, which was implemented during the fourth quarter of the prior year.

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Energy Investments

Jefferson Island This wholly owned subsidiary operates a salt dome storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. The storage facility is regulated by the Louisiana Department of Natural Resources (Louisiana DNR) and by the FERC which has limited regulatory authority over the storage and transportation services. The facility consists of two salt dome gas storage caverns with approximately 9.72 Bcf of total capacity and about 7.23 Bcf of working gas capacity. The facility has approximately 0.72 Bcf/day withdrawal capacity and 0.36 Bcf/day injection capacity. Jefferson Island provides storage and hub services through its direct connection to the Henry Hub via the Sabine Pipeline and its interconnection with seven other pipelines in the area. Jefferson Island's entire portfolio is under firm subscription for the 2006-2007 winter period.

In August 2006, the Office of Mineral Resources of the Louisiana DNR informed Jefferson Island that its mineral lease - which authorizes salt extraction to create two new storage caverns - at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. We continue to seek resolution of this dispute and we are optimistic that a settlement can be reached with the State of Louisiana that would allow us to proceed with the expansion. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2007, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $8 million.

Golden Triangle Storage In December 2006, we announced plans to build an approximate $180 million natural gas storage facility in the Beaumont, Texas area in the Spindletop salt dome. The project will consist of two underground salt dome storage caverns approximately a half-mile to a mile below ground that will hold about 12 Bcf of working natural gas, or 17 Bcf total storage capacity. Golden Triangle Storage expects to finalize engineering plans and obtain regulatory permits to begin construction in 2008. The first salt dome cavern is expected to begin operations in 2010, and the second cavern is expected to begin operations in 2012.

Pivotal Propane In 2005, this wholly owned subsidiary completed the construction of a propane air facility in the Virginia Natural Gas service area that provides up to 0.03 Bcf/day of propane air on a 10-day-per-year basis to serve Virginia Natural Gas' peaking needs.

AGL Networks This wholly owned subsidiary provides telecommunications conduit and dark fiber. AGL Networks leases and sells its fiber to a variety of customers in the Atlanta, Georgia and Phoenix, Arizona 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 companies. 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.

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Results of Operations The following table presents results of operations for energy investments for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Operating revenues	$ 41	$ 56	$ 25
Cost of sales	5	16	12
Operating margin (1)	36	40	13
Operating expenses	26	23	8
Operating income	10	17	5
Other income	-	2	2
EBIT (1)	$ 10	$ 19	$ 7

(1) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations - AGL Resources."

2006 compared to 2005 The $9 million or 47% decrease in EBIT is due primarily to the loss of operating margin and other income contributions from the 2005 sale of certain assets that we originally acquired with the 2004 acquisition of NUI and an increase in operating expenses due to higher business development expenses and increased costs at Jefferson Island offset by lower expenses related to the sale of the former NUI assets in 2005.

Operating margin decreased $4 million or 10% largely due to the loss of $9 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but sold in 2005. Jefferson Island's operating margin increased by $1 million compared to the prior year, in part due to increases in both firm and interruptible margin opportunities. AGL Networks' operating margin increased by $1 million due to a larger customer base. Pivotal Propane contributed a $2 million increase primarily in the first quarter of 2006 as it did not become operational until April 2005.

Operating expenses increased $3 million or 13% compared to 2005. Operating expenses at Pivotal Propane increased as it did not become operational until April 2005. Jefferson Island's operating expenses increased by $2 million due to the installation of new compression equipment and higher legal costs and property taxes. Additionally, project and corporate development costs increased $9 million. These costs were offset by decreased operating expenses of $8 million resulting from the 2005 sale of certain assets that we originally acquired with the 2004 acquisition of NUI. Other income decreased by $2 million due to the loss of earnings contributions from certain assets we acquired with the 2004 acquisition of NUI but sold in 2005.

2005 compared to 2004 The $12 million or 171% increase in EBIT in 2005 was primarily the result of increased operating margin of $27 million, offset by $15 million in higher operating expenses.

Of the $27 million or 208% increase in operating margin, $13 million resulted from Jefferson Island, $8 million resulted from NUI's nonutility businesses and $3 million resulted from Pivotal Propane. AGL Networks contributed $4 million primarily as a result of recurring revenues from fiber leasing activities of $1 million and construction and new business activities of $3 million.

Of the $15 million or 188% increase in operating expenses, $8 million resulted from NUI's nonutility businesses, $3 million resulted from Jefferson Island and $3 million resulted from Pivotal Propane. AGL Networks' operating expenses were relatively flat in 2005 as compared to 2004.

Corporate

Our corporate segment includes our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital). AGL Capital provides for our ongoing financing needs through a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

Pivotal Energy Development coordinates among our related operating segments, the development, construction or acquisition of assets in the southeastern, mid-Atlantic and northeastern regions in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in those areas. The focus of Pivotal Energy Development's commercial activities is to improve the economics of system reliability and natural gas deliverability in these targeted regions.

We allocate substantially all of AGSC's operating expenses and interest costs to our operating segments in accordance with various regulations. 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. The acquisition of additional assets, such as NUI and Jefferson Island, typically enables us to allocate corporate costs across a larger number of businesses and, as a result, lower the relative allocations charged to those business units we owned prior to the acquisition of the new businesses.

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Results of Operations The following table presents results of operations for our corporate segment for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Operating revenues	$ (156)	$ (182)	$ (185)
Cost of sales	(157)	(182)	(184)
Operating margin (1) (2)	1	-	(1)
Operating expenses (3)	9	6	12
Operating loss	(8)	(6)	(13)
Other expenses	(1)	(5)	(3)
EBIT (2)	$ (9)	$ (11)	$ (16)

(1) Includes intercompany eliminations

(2) These are non-GAAP measurements. A reconciliation of operating margin and EBIT to our operating income and net income is contained in "Results of Operations - AGL Resources."

(3) The following table summarizes the major components of operating expenses.

In millions	2006	2005	2004
Payroll	$ 55	$ 57	$ 48
Benefits and incentives	36	34	32
Outside services	41	43	29
All other expenses	50	57	50
Allocations	(173)	(185)	(147)
Total operating expenses	$ 9	$ 6	$ 12

The corporate segment is a nonoperating segment. As such, changes in EBIT amounts for the indicated periods reflect the relative changes in various general and administrative expenses, such as payroll, benefits and incentives, and outside services.

Liquidity and Capital Resources

To meet our capital and liquidity requirements we rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our Credit Facility; borrowings under Sequent's and SouthStar's lines of credit; and borrowings or stock issuances in the long-term capital markets. Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. 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. The availability of borrowings under our Credit Facility is limited and subject to a total debt-to-capital ratio financial covenant specified within the Credit Facility, which we currently meet.

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. Additionally, our liquidity and capital resource requirements may change in the future due to a number of other factors, some of which we cannot control. These factors include:

- the seasonal nature of the natural gas business and our resulting short-term borrowing requirements, which typically peak during colder months
- increased gas supplies required to meet our customers' needs during cold weather
- changes in wholesale prices and customer demand for our products and services

- regulatory changes and changes in ratemaking policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks
- the impact of natural disasters, including weather

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Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations may result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. The following table illustrates our expected future contractual obligations as of December 31, 2006.

		Payments due before December 31,			
In millions	**Total**	**2007**	**2008 & 2009**	**2010 & 2011**	**2012 & thereafter**
Interest charges (1)	$ 1,398	$ 99	$ 198	$ 177	$ 924
Pipeline charges, storage capacity and gas supply (2) (3) (4)	1,916	441	625	389	461
Long-term debt (5)	1,622	-	-	300	1,322
Short-term debt	539	539	-	-	-
PRP costs (6)	237	35	82	85	35
Operating leases (7)	170	32	47	34	57
ERC (6)	96	13	18	54	11
Total	$ 5,978	$ 1,159	$ 970	$ 1,039	$ 2,810

(1) Floating rate debt is based on the interest rate as of December 31, 2006 and the maturity of the underlying debt instrument.
(2) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.
(3) A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS No. 141, "Business Combinations," we valued the contracts at fair value and established a long-term liability that will be amortized over the remaining lives of the contracts.
(4) Amount includes SouthStar gas commodity purchase commitments of 1.4 Bcf at floating gas prices calculated using forward natural gas prices as of December 31, 2006, and is valued at $89 million.
(5) Includes $77 million of notes payable to Trusts redeemable in 2007.
(6) Includes charges recoverable through rate rider mechanisms.
(7) 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 SFAS No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

We calculate any required pension contributions using the projected unit credit cost method. Under this method, we were not required to make any pension contribution in 2006,
but we voluntarily made a $5 million contribution in October 2006. See Note 4 "Employee Benefit Plans," for additional pension information.

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. The following table illustrates our expected contingent financial commitments as of December 31, 2006.

In millions	**Total**	**2007**	**Commitments due before Dec. 31, 2008 & thereafter**
Standby letters of credit, performance/ surety bonds	$ 14	$ 12	$ 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 do not result in actual cash receipts or payments during the period. These reconciling items include depreciation, changes in risk management assets and liabilities, undistributed earnings from equity investments, changes in deferred income taxes, gains or losses on the sale of assets and changes in the consolidated balance sheet for working capital from the beginning to the end of the period.

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Year-over-year changes in our operating cash flows are attributable primarily to working capital changes within our distribution operations, wholesale services and retail energy operations 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.

We generate a large portion of our annual net income and subsequent increases in our accounts receivable in the first and fourth quarters of each year due to significant volumes of natural gas delivered by distribution operations and SouthStar to our customers during the peak heating season. In addition, our natural gas inventories, which usually peak on November 1, are largely drawn down in the heating season and provide a source of cash as this asset is used to satisfy winter sales demand.

During this period, our accounts payable increases to reflect payments due to providers of the natural gas commodity and pipeline capacity. The value of the natural gas commodity can vary significantly from one period to the next as a result of volatility in the price of natural gas. Our natural gas costs and deferred purchased natural gas costs due from or to our customers represent the difference between natural gas costs that we have paid to suppliers in the past and amounts that we have collected from customers. These natural gas costs can cause significant variations in cash flows from period to period.

In 2006, our net cash flow provided from operating activities was $354 million, an increase of $274 million or 343% from the same period of 2005. The increase was primarily a result of higher earnings in 2006 of $19 million, the recovery of working capital during 2006 that was deployed in 2005 due to the significantly higher commodity prices and the amount of working capital required during the last quarter of 2004 when prices were significantly lower. Contributing to this increase was a decrease in the amount of natural gas purchased for inventory at Sequent and our utilities of $157 million as a result of mild weather in the prior heating season and therefore higher inventory balances for the current heating season.

In 2005, our net cash flow provided from operating activities was $80 million, a decrease of $207 million or 72% from the same period of 2004. The decrease was primarily a result of increased working capital requirements including increased spending of $183 million for seasonal inventory injections in advance of the winter sales demand. We spent more on these injections in 2005 primarily because of higher natural gas prices due to the effects of the hurricanes in the Gulf Coast region and the full-year impact associated with the purchase of natural gas for the utilities acquired in November 2004 from NUI, principally Elizabethtown Gas. These higher natural gas prices resulted in a 45% increase in the average cost of our natural gas inventories.

Cash Flow from Investing Activities Our investing activities consisted primarily of property, plant and equipment (PP&E) expenditures and our acquisitions of NUI for $116 million and Jefferson Island for $90 million in 2004. Additionally in 2006, we received approximately $5 million for the sale of land associated with former operating sites. In 2005, we sold our 50% interest in Saltville Gas Storage Company (Saltville) and associated subsidiaries for $66 million to a subsidiary of Duke Energy Corporation. We acquired Saltville through our acquisition of NUI. In 2004, we sold our general and limited partnership interests in US Propane LP, which was a joint venture formed in 2000, for $31 million. The following table provides additional information on our actual and estimated PP&E expenditures.

In millions	**2007** (1)	**2006**	**2005**	**2004**
Construction or preservation of distribution facilities	$ 159	$ 144	$ 135	$ 64
Southern Natural Gas pipeline	-	-	32	-
PRP	35	31	48	95

Pivotal Propane plant	-	-	-	29
Jefferson Island	53	20	8	2
Telecommunications	3	3	1	5
Other (2)	28	55	43	69
Total	$ 278	$ 253	$ 267	$ 264

(1) Estimated

(2) Includes corporate information technology systems and infrastructure expenditures.

The decrease of $14 million or 5% in PP&E expenditures for 2006 compared to 2005 was primarily due to the $32 million acquisition of a 250-mile pipeline in Georgia from Southern Natural Gas (SNG) in 2005 and $7 million for construction of distribution facilities in Georgia. This was offset by higher expenditures of $8 million at the corporate segment primarily on information technology projects, $12 million at Jefferson Island on its expansion project and $5 million at retail energy operations primarily due to the implementation of a new ETRM system and enhancements to the retail billing system.

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The increase of $3 million or 1% in PP&E expenditures for 2005 compared to 2004 was primarily due to the $32 million acquisition of the SNG pipeline in 2005 and increased expenditures of $71 million for the construction of distribution facilities, including $27 million at Elizabethtown Gas and Florida City Gas, both of which were acquired in November 2004. Also contributing to the increase was $6 million of additional expenditures at Jefferson Island which completed a capital project to improve its compression capabilities. These increases were offset by reduced PRP expenditures of $47 million due to the rate case settlement agreement between Atlanta Gas Light and the Georgia Commission that extended the program to 2013, reduced expenditures of $29 million at the Pivotal Propane plant in Virginia as most of its construction expenditures were incurred in 2004 and reduced expenditures at Sequent as its energy trading risk management (ETRM) system was implemented in 2004.

We expect our future PRP expenditures will primarily include larger-diameter pipe than in prior years, the majority of which is located in more densely populated areas. The following table provides more information on our expected PRP expenditures.

Year	Miles of pipe to be replaced	Expenditures (in millions)
2007	107	$ 35
2008	144	38
2009	147	44
2010-2013	337	120
Totals	735	$ 237

Cash Flow from Financing Activities Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of medium-term notes, borrowings of senior notes, distributions to minority interests, cash dividends on our common stock issuances, and purchases and issuances of treasury shares. 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 25% to 45% of total debt), as well as the term and interest rate profile of our debt securities. As of December 31, 2006, our variable-rate debt was $733 million or 34% of our total debt. This included $527 million of variable-rate short-term debt, $100 million of variable-rate senior notes and $106 million of variable-rate gas facility revenue bonds. In 2005, our variable-rate debt was also 34% of our total debt.

We also work to maintain or improve our credit ratings on our debt to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our balance sheet 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 table below summarizes our credit ratings as of December 31, 2006, which reflects no change from last year.

	S&P	Moody's	Fitch
Corporate rating	A-		
Commercial paper	A-2	P-2	F-2
	BBB+	Baa1	A-

Senior unsecured			
Ratings outlook	Negative	Stable	Stable

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.

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. Our Credit Facility’s financial covenant requires 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%. We are currently in compliance with all existing debt provisions and covenants. For more information on our debt, see Note 7 “Debt.”

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We believe that accomplishing these 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. The components of our capital structure, as of the dates indicated, are summarized in the following tables.

In millions	Dec. 31, 2006	
Short-term debt	$ 539	14%
Long-term debt (1)	1,622	43
Total debt	2,161	57
Common shareholders' equity	1,609	43
Total capitalization	$ 3,770	100%

In millions	Dec. 31, 2005	
Short-term debt	$ 522	14%
Long-term debt (1)	1,615	45
Total debt	2,137	59
Common shareholders' equity	1,499	41
Total capitalization	$ 3,636	100%

(1) Net of interest rate swaps.

Short-term Debt Our short-term debt is composed of borrowings under our commercial paper program, lines of credit at Sequent, SouthStar and Pivotal Utility, the current portion of our medium-term notes and 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.

In August 2006, we replaced our previous Credit Facility with a new Credit Facility that supports our commercial paper program. Under the terms of the new Credit Facility, the aggregate principal amount available has been increased from $850 million to $1 billion and we can request an option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year. This Credit Facility expires August 31, 2011. The increased capacity under our Credit Facility increases our ability to borrow under our commercial paper program. Our total cash and available liquidity under our Credit Facility as of the dates indicated are shown in the table below.

In millions	Dec. 31, 2006	Dec. 31, 2005
Unused availability under the Credit Facility	$ 1,000	$ 850
Cash and cash equivalents	20	32
Total cash and available liquidity under the Credit Facility	$ 1,020	$ 882

As of December 31, 2006 and 2005, we had no outstanding borrowings under the Credit Facility. However, the availability of borrowings and unused availability under our Credit Facility is limited and subject to conditions specified within the Credit Facility, which we currently meet. These conditions include:

- the maintenance of a ratio of total debt to total capitalization of no greater than 70%
- the continued accuracy of representations and warranties contained in the agreement

In 2006, we extended Sequent's two lines of credit through June 2007 and August 2007. In addition, we extended Pivotal Utility's line of credit through August 2007. These unsecured lines of credit are unconditionally guaranteed by us.

In November of 2006, SouthStar closed a five-year $75 million credit facility. This facility will be used for working capital needs and general corporate needs. At December 31, 2006, there were no outstanding borrowings on this line of credit.

Long-term Debt In May 2006, we used the proceeds from the sale of commercial paper to redeem $150 million of junior subordinated debentures and to pay a $5 million note representing our investment in our Capital Trust, previously included in notes payable to trusts. In June 2006, we issued $175 million of 10-year senior notes at an interest rate of 6.375% and used the net proceeds of $173 million to repay the commercial paper. 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.

Interest Rate Swaps To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate debt and variable-rate debt. We have entered into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligation.

Minority Interest As a result of our consolidation of SouthStar's accounts effective January 1, 2004, we recorded Piedmont's portion of SouthStar's contributed capital as a minority interest in our consolidated balance sheets and included it as a component of our total capitalization. A cash distribution of $22 million in 2006, $19 million in 2005 and $14 million in 2004 for SouthStar's dividend distributions to Piedmont were recorded in our consolidated statement of cash flows as a financing activity.

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Dividends on Common Stock In 2006, we made $111 million in common stock dividend payments. This was an increase of $11 million or 11% from 2005, which resulted from increases in the amount of our quarterly common stock dividends per share. In 2005, we made $100 million in common stock dividend payments. This was an increase of $25 million or 33% from 2004. The increase was due to our 11 million share common stock offering in November 2004, which increased the number of shares outstanding, and the increases in the amount of our quarterly common stock dividends per share.

In the last three fiscal years, we have made the following increases in dividends on our common stock. For information about restrictions on our ability to pay dividends on our common stock, see Note 6.

Date of change	% increase	Quarterly dividend	Indicated annual dividend
Nov 2005	19%	$ 0.37	$ 1.48
Feb 2005	7	0.31	1.24
Apr 2004	4	0.29	1.16

Share Repurchases In March 2001 our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. During 2006, we purchased 32,801 shares. As of December 31, 2006, we had purchased a total 286,567 shares, leaving 313,433 shares available for purchase.

In February 2006, our Board of Directors authorized a plan to purchase up to eight 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 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. During 2006, we repurchased 1,027,500 shares at a weighted average price of $36.67. For more information on our share repurchases see Item 5 "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities."

Shelf Registration We currently have remaining capacity under an October 2004 shelf registration statement of approximately $782 million. We may seek additional financing through debt or equity offerings in the private or public markets at any time.

Critical Accounting Policies

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 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. Our actual results may differ from our estimates. Each of the following critical accounting policies 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 Atlanta Gas Light was ordered by the Georgia Commission (through a joint stipulation between Atlanta Gas Light and the Commission staff) to undertake a PRP that would replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light identified and, in accordance with this stipulation, provided notice to the Georgia Commission of 2,632 miles of bare steel and cast iron pipe to be replaced.

On June 10, 2005, the Georgia Commission approved a Settlement Agreement with Atlanta Gas Light that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013. Approximately 131 miles of cast iron and 604 miles of bare steel pipe still require replacement. If Atlanta Gas Light does not perform in accordance with the initial and amended PRP stipulation, it can be assessed certain nonperformance penalties. However, to date, Atlanta Gas Light is in full compliance.

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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 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. Atlanta Gas Light recorded a long-term liability of $202 million as of December 31, 2006 and $235 million as of December 31, 2005, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2006, Atlanta Gas Light had recorded a current liability of $35 million, representing expected PRP expenditures for the next 12 months. We report these estimates on an undiscounted basis. If the recorded liability for PRP had been higher or lower by $10 million, Atlanta Gas Light’s expected recovery would have changed by approximately $1 million.

Environmental Remediation Liabilities Atlanta Gas Light 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 cleanup contracts, Atlanta Gas Light is increasingly able to provide conventional engineering estimates of the likely costs of many elements of its remediation program. These estimates contain various engineering uncertainties, and Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Our latest available estimate as of December 31, 2006 for those elements of the remediation program with in-place contracts or engineering cost estimates is $13 million for Atlanta Gas Light’s Georgia and Florida sites. This is an increase of $1 million from the December 31, 2005 estimate of projected engineering and in-place contracts, resulting from increased cost estimates during 2006. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $14 million. Atlanta Gas Light estimates certain other costs it pays related to administering the remediation program and remediation of sites currently in the investigation phase. Beyond 2008, these costs cannot be estimated.

Atlanta Gas Light’s environmental remediation liability is included in its corresponding regulatory asset. As of December 31, 2006, the regulatory asset was $104 million, which is a combination of the accrued remediation liability and unrecovered cash expenditures. 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. Although the actual total cost of future environmental investigation and remediation efforts cannot be estimated with precision, the range of reasonably probable costs is $60 million to $118 million. As of December 31, 2006, we have recorded a liability of $60 million.

The New Jersey Commission has authorized Elizabethtown Gas to recover prudently incurred remediation costs for the New Jersey properties through its remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $66 million, inclusive of interest, as of December 31, 2006, reflecting the future recovery of both incurred costs and future remediation liabilities in the state of New Jersey. Elizabethtown Gas has also 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, 2006, the variation between the amounts of the environmental remediation cost liability recorded in the consolidated balance sheet and the associated regulatory asset is due to expenditures for environmental investigation and remediation exceeding recoveries from ratepayers and insurance carriers.

We also own several former NUI 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. Preliminary estimates for investigation and remediation costs range from $10 million to $17 million. As of December 31, 2006, we had recorded a liability of $10 million related to this site. There is another site in North Carolina where investigation and remediation is probable, although no regulatory order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted. We do not believe that costs to investigate and remediate these sites, if any, can be reasonably estimated at this time.

With respect to these costs, we currently pursue or intend to pursue recovery from ratepayers, former owners and operators and insurance carriers. Although 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 prudently 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 SFAS 133, as updated by SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (SFAS 149), established accounting and reporting standards which require that every derivative financial instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet 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 SFAS 133, as updated by SFAS 149, and is accounted for using traditional accrual accounting.

SFAS 133 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, SFAS 133 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 maturity in the case of a cash flow hedge. Additionally, SFAS 133 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. SFAS 133 applies to Treasury Locks and interest rate swaps executed by AGL Capital and gas commodity contracts executed by both Sequent and SouthStar. Our derivative and hedging activities are described in further detail in Note 1, "Accounting Policies and Methods of Application," Note 2 "Risk Management" and Item 7 "Management's Discussion and Analysis of Financial Condition and Results of Operations."

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 instruments to reduce our exposure to the risk of changes in the price of natural gas.

Sequent recognizes the change in value of derivative instruments 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 balance sheet separately from the risk management activities reported as energy marketing receivables and trade payables.

We attempt to mitigate substantially all 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 over-the-counter derivatives in the forward months corresponding with our withdrawal periods. We use contracts to sell natural gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored natural gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

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. The difference in accounting can result in volatility in our reported net income, even though the economic margin is essentially unchanged from the date the transactions were consummated. We do not currently use hedge accounting under SFAS 133 to account for this activity.

Natural gas that we purchase and inject into storage is accounted for at the lower of average cost or market. Under current accounting guidance, we would 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 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 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.

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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.

See "Results of Operations - Wholesale Services" for a discussion of the potential volatility in earnings due to changes in natural gas prices.

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 SFAS 133. 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, 2006, the ending balance in OCI for derivative transactions designated as cash flow hedges under SFAS 133 was a gain of $6 million, net of minority 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 SFAS 133. 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 preserve margins in the event of warmer-than-normal weather in the winter months. These contracts are accounted for using the intrinsic value method under the guidance of EITF Issue No. 99-02, "Accounting for Weather Derivatives." Changes in the fair 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 September 2006, SouthStar entered into weather derivatives (swaps and options) for the 2006-2007 winter heating season, primarily from November through March. As of December 31, 2006, SouthStar recorded a receivable of $7 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 SFAS No. 5, "Accounting for 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 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 used principally to calculate the actuarial present value of our pension and postretirement obligations and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Corporate AA long-term bond rate of 5.8% and the Citigroup Pension Liability rate of 5.9% at December 31, 2006. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors. This analysis as of December 31, 2006 produced a single equivalent discount rate of 5.8%.

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The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. These differences may result in a significant impact on the amount of pension expense recorded in future periods.

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.

Prior to 2006, we estimated the assumed health care cost trend rate used in determining our postretirement net expense based on our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. However, starting in 2006, our postretirement plans have been capped at 2.5% for increases in health care costs. Consequently, a one-percentage-point increase or decrease in the assumed health care trend rate does not materially affect the periodic benefit cost for our postretirement plans. A one-percentage-point increase in the assumed health care cost trend rate would increase our accumulated projected benefit obligation by $4 million. A one percentage-point decrease in the assumed health care cost trend rate would decrease our accumulated projected benefit obligation by $4 million. Our assumed rate of retirement is estimated based upon an annual review of participant census information as of the measurement date.

At December 31, 2006, our pension and postretirement liability decreased by approximately $18 million, resulting in an after-tax gain to OCI of $11 million. This adjustment reflected our funding contributions to the plan 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 accumulated benefit obligation (ABO), as the primary factors that drive the value of our unfunded ABO 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 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.

The actual return on our pension plan assets compared to the expected return on plan assets will have an impact on our ABO as of December 31, 2006 and our pension expense for 2007. We are unable to determine how this actual return on plan assets will affect future ABO and pension expense, as actuarial assumptions and differences between actual and expected returns on plan assets are determined at the time we complete our actuarial evaluation as of December 31, 2006. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets. The following tables illustrate the effect of changing the critical actuarial assumptions, as discussed above, while holding all other assumptions constant:

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AGL Resources Inc. Retirement and Postretirement Plans

In millions	Pension Benefits			Health and Life Benefits	
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost	Increase (decrease) in obligation	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(3) / 3		
Discount rate	+/- 1%	(40) / 45	(4) / 4		
Healthcare cost trend rate	+/- 1%			$4 / (4)	$- / -

NUI Corporation Retirement Plan

In millions	Pension Benefits		
Actuarial assumptions	Percentage-point change in assumption	Increase (decrease) in ABO	Increase (decrease) in cost
Expected long-term return on plan assets	+/- 1%	$- / -	$(1) / 1
Discount rate	+/- 1%	(8) / 8	- / -

At December 31, 2006, NUI's PBO was $86 million, reflecting $12 million in adjustments for terminations and settlement of liabilities affected by the NUI purchase transaction, offset by net periodic benefit cost of $3 million in 2006. 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.

In addition to the assumptions listed above, the measurement of the plans' obligations and costs depend on other factors such as employee demographics, the level of contributions made to the plans, earnings on the plans' assets and mortality rates.

Income Taxes Our net long-term deferred tax liability totaled $544 million at December 31, 2006 (see Note 10 "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 $47 million of deferred tax assets as of December 31, 2006, reflecting the expectation that most of these assets will be realized. In addition, we maintain a liability for the estimate of potential income tax exposure. We believe this liability for potential exposure to be adequate.

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Accounting Developments

For information regarding accounting developments, see Note 1, “Accounting Policies and Methods of Application.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. 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 commodity 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, “Risk Management.”

Commodity Price Risk

Retail Energy Operations SouthStar’s use of derivatives is governed by a risk management policy, approved and monitored by its Risk and Asset Management Committee, which prohibits the use of derivatives for speculative purposes. A 95% confidence interval is used to evaluate VaR exposure. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value over the holding period. We calculate VaR based on the variance-covariance technique. This technique requires several assumptions for the basis of the calculation, such as 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. The following table provides more information on SouthStar’s 1-day holding period VaR.

In millions	**1-day**
2006 period end	$ 0.1
2005 period end	0.3

SouthStar generates operating margin from the active management of storage positions through a variety of hedging transactions and derivative instruments aimed at managing exposures arising from changing commodity prices. SouthStar uses these hedging instruments to lock in economic margins as wholesale prices fluctuate and thereby minimize its exposure to declining operating margins.

Wholesale Services Sequent routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements. The following table includes the fair values and average values of Sequent’s energy marketing and risk management assets and liabilities as of December 31, 2006 and 2005. Sequent bases the average values on monthly averages for the 12 months ended December 31, 2006 and 2005.

	Average values at December 31,	
In millions	**2006**	**2005**
Asset	$ 95	$ 83
Liability	43	102

	Fair value at December 31,	
In millions	**2006**	**2005**
Asset	$ 133	$ 97
Liability	14	110

Sequent employs a systematic approach to evaluating and managing the risks associated with contracts related to wholesale marketing and risk management, including VaR. Similar to SouthStar, Sequent uses a 1-day holding period and a 95% confidence interval to evaluate its VaR exposure.

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 and over-the-counter markets, its open exposure is generally minimal, 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.

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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 commodity 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, 2006, 2005 and 2004 had the following 1-day holding period VaRs.

In millions	**2006**	**2005**	**2004**
Period end	$ 1.3	$ 0.6	$ 0.1
12-month average	1.2	0.4	0.1
High	2.5	1.1	0.4
Low (1)	0.7	0.0	0.0

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

During most of 2005 and 2006, Sequent experienced increases in its high, average and period end 1-day VaR amounts compared to prior periods. These increases were directly associated with higher prices and related price volatility created by the Gulf Coast hurricanes during the third quarter of 2005 and the hurricanes' lingering effects through the fourth quarters of 2005 and into 2006. In addition, Sequent has entered into additional storage and transportation positions, some of which are longer dated and are not fully hedged due to a lack of liquidity in certain markets for the future periods. As a result, these positions have increased Sequent's reported VaR amounts.

Sequent has refined the methodology associated with its VaR calculation to incorporate dynamic volatility factors and to exclude interruptible transportation positions. These changes had somewhat offsetting effects as the dynamic volatility factors increased the VaR and the exclusion of interruptible transportation positions reduced the VaR. This new methodology was applied on a prospective basis beginning in the second quarter of 2006. While not considered material, Sequent's VaR amounts increased compared to prior periods as its calculation is now more sensitive to market volatility and the relative level of risk associated with increased storage and transportation positions. Due to the dynamic nature of measuring VaR, Sequent will continually evaluate the components of its VaR calculation and will make refinements as deemed necessary.

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. To facilitate the achievement of desired fixed-rate to variable-rate debt ratios, AGL Capital entered into interest rate swaps whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-on notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million Senior Notes due in 2011.

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills only 11 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 2006, the four largest Marketers based on customer count, one of which was

SouthStar, accounted for approximately 36% of our consolidated operating margin and 47% 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 to Marketers of interstate pipeline transportation and storage capacity. 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. The fact that some of the interstate pipelines require Marketers to maintain security for their obligations to the interstate pipelines arising out of the assigned capacity somewhat mitigates this risk.

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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. The average credit score of SouthStar's Georgia customers has increased 3% since 2004.

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 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 meet the minimum ratings threshold.

Sequent, which provides services to 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, 2006, Sequent's top 20 counterparties represented approximately 57% of the total counterparty exposure of $394 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

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As of December 31, 2006, 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's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following tables show Sequent's commodity receivable and payable positions as of December 31, 2006 and 2005.

	As of December 31,	
In millions	**2006**	**2005**
Gross receivables		
Receivables with netting agreements in place:		
Counterparty is investment grade	$ 359	$ 462
Counterparty is non-investment grade	62	66
Counterparty has no external rating	75	113
Receivables without netting agreements in place:		
Counterparty is investment grade	9	34
Amount recorded on balance sheet	$ 505	$ 675

Gross payables		
Payables with netting agreements in place:		
Counterparty is investment grade	$ 297	$ 456
Counterparty is non-investment grade	52	56
Counterparty has no external rating	156	255
Payables without netting agreements in place:		
Counterparty is investment grade	5	4
Counterparty has no external rating	-	4

Amount recorded on balance sheet	$	510	$	775

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. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at December 31, 2006 Sequent's 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 $10 million.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AGL Resources Inc.
Consolidated Balance Sheets - Assets

In millions	As of December 31, 2006	December 31, 2005
Current assets		
Cash and cash equivalents	$ 20	$ 32
Receivables		
Energy marketing	505	675
Gas	197	303
Unbilled revenues	172	246
Other	21	11
Less allowance for uncollectible accounts	(15)	(15)
Total receivables	880	1,220
Inventories		
Natural gas stored underground	568	509
Other	29	34
Total inventories	597	543
Energy marketing and risk management assets	159	103
Unrecovered environmental remediation costs - current portion	27	31
Unrecovered PRP costs - current portion	27	27
Other current assets	112	85
Total current assets	1,822	2,041
Property, plant and equipment		
Property, plant and equipment	4,976	4,791
Less accumulated depreciation	1,540	1,458
Property, plant and equipment -- net	3,436	3,333
Deferred debits and other assets		
Goodwill	420	420
Unrecovered PRP costs	247	276
Unrecovered environmental remediation costs	143	165
Other	79	85
Total deferred debits and other assets	889	946
Total assets	$ 6,147	$ 6,320

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Consolidated Balance Sheets - Liabilities and Capitalization

In millions, except share amounts	As of December 31, 2006	December 31, 2005
Current liabilities		
Short-term debt	$ 539	$ 522
Energy marketing trade payable	510	775
Accounts payable - trade	213	266
Accrued wages and salaries	50	43
Customer deposits	42	42
Energy marketing and risk management liabilities - current portion	41	117
Accrued interest	37	32
Accrued PRP costs - current portion	35	30
Deferred purchased gas adjustment	24	40
Accrued environmental remediation costs - current portion	13	13
Other current liabilities	123	88
Total current liabilities	1,627	1,968
Accumulated deferred income taxes	544	423
Long-term liabilities		
Accrued PRP costs	202	235
Accumulated removal costs	162	156
Accrued environmental remediation costs	83	84
Accrued pension obligations	78	88
Accrued postretirement benefit costs	32	50
Other long-term liabilities	146	164
Total long-term liabilities	703	777
Commitments and contingencies (see Note 8)		
Minority interest	42	38
Capitalization		
Long-term debt	1,622	1,615
Common shareholders' equity, $5 par value; 750 million shares authorized; 77.7 million and 77.8 million shares outstanding at December 31, 2006 and 2005	1,609	1,499
Total capitalization	3,231	3,114
Total liabilities and capitalization	$ 6,147	$ 6,320

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Statements of Consolidated Income

In millions, except per share amounts	Years ended December 31, 2006	2005	2004
Operating revenues	$ 2,621	$ 2,718	$ 1,832
Operating expenses			
Cost of gas	1,482	1,626	995
Operation and maintenance	473	477	377
Depreciation and amortization	138	133	99
Taxes other than income taxes	40	40	29
Total operating expenses	2,133	2,276	1,500
Operating income	488	442	332
Other expenses	(1)	(1)	-
Minority interest	(23)	(22)	(18)
Interest expense	(123)	(109)	(71)
Earnings before income taxes	341	310	243
Income taxes	129	117	90
Net income	$ 212	$ 193	$ 153
Per common share data			
Basic earnings per common share	$ 2.73	$ 2.50	$ 2.30
Diluted earnings per common share	$ 2.72	$ 2.48	$ 2.28
Cash dividends declared per common share	$ 1.48	$ 1.30	$ 1.15
Weighted average number of common shares outstanding			
Basic	77.6	77.3	66.3
Diluted	78.0	77.8	67.0

See Notes to Consolidated Financial Statements.

AGL Resources Inc.
Statements of Consolidated Common Shareholders' Equity

In millions, except per share amounts	Common stock Shares	Common stock Amount	Premium on common stock	Earnings reinvested	Other comprehensive loss	Shares held in treasury and trust	Total
Balance as of December 31, 2003	64.5	$ 322	$ 326	$ 337	$ (40)	-	$ 945
Comprehensive income:							
Net income	-	-	-	153	-	-	153
Other comprehensive income (OCI) - loss resulting from unfunded pension obligation (net of tax of $7)	-	-	-	-	(11)	-	(11)
Unrealized gain from equity investment hedging activities (net of tax of $2)	-	-	-	-	4	-	4
Other					1		1
Total comprehensive income							147
Dividends on common stock ($1.15 per share)	-	-	-	(75)	-	-	(75)
Issuance of common shares:							
Equity offering on November 24, 2004	11.0	55	277	-	-	-	332
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax of $5)	1.2	7	29	-	-		36
Balance as of December 31, 2004	76.7	384	632	415	(46)	-	1,385
Comprehensive income:							
Net income	-	-	-	193	-	-	193
OCI - loss resulting from unfunded pension obligation (net of tax of $3)	-	-	-	-	(5)	-	(5)
Unrealized loss from hedging activities (net of tax of $1)	-	-	-	-	(2)	-	(2)
Other	-	-	-	-	-	-	-
Total comprehensive income							186
Dividends on common stock ($1.30 per share)	-	-	-	(100)	-	-	(100)
Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax of $9)	1.1	5	23	-	-	-	28
Balance as of December 31, 2005	77.8	389	655	508	(53)	-	1,499
Comprehensive income:							
Net income	-	-	-	212	-	-	212
OCI - gain resulting from unfunded pension and postretirement obligation (net of tax of $7)	-	-	-	-	11	-	11
Unrealized gain from hedging activities (net of tax of $7)	-	-	-	-	10	-	10

Total comprehensive income							233
Dividends on common stock ($1.48 per share)	-	-	1	(115)	-	3	(111)
Benefit, stock compensation, dividend reinvestment and stock purchase plans	0.3	1	2	-	-	-	3
Issuance of treasury shares	0.6	-	(3)	(4)	-	21	14
Purchase of treasury shares	(1.0)	-	-	-	-	(38)	(38)
Stock-based compensation expense (net of tax of $5)	-	-	9	-	-	-	9
Balance as of December 31, 2006	77.7	$ 390	$ 664	$ 601	$ (32)	$ (14)	$ 1,609

See Notes to Consolidated Financial Statements.

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AGL Resources Inc.
Statements of Consolidated Cash Flows

	Years ended December 31,		
In millions	2006	2005	2004
Cash flows from operating activities			
Net income	$ 212	$ 193	$ 153
Adjustments to reconcile net income to net cash flow provided by operating activities			
Depreciation and amortization	138	133	99
Minority interest	23	22	18
Change in risk management assets and liabilities	(130)	27	(32)
Deferred income taxes	133	17	65
Changes in certain assets and liabilities			
Receivables	340	(338)	(264)
Inventories	(54)	(211)	(28)
Payables	(318)	311	247
Other - net	12	(74)	29
Net cash flow provided by operating activities	354	80	287
Cash flows from investing activities			
Expenditures for property, plant and equipment	(253)	(267)	(264)
Sale of Saltville Gas Storage Company, LLC	-	66	-
Acquisition of NUI Corporation, net of cash acquired	-	-	(116)
Acquisition of Jefferson Island Storage & Hub, LLC	-	-	(90)
Sale of US Propane LP	-	-	31
Other	5	7	17
Net cash flow used in investing activities	(248)	(194)	(422)
Cash flows from financing activities			
Payments of trust preferred securities	(150)	-	-
Dividends paid on common shares	(111)	(100)	(75)
Purchase of treasury shares	(38)	-	-
Distribution to minority interest	(22)	(19)	(14)
Issuances of senior notes	175	-	450
Issuance of treasury shares	14	-	-
Net payments and borrowings of short-term debt	6	188	(480)
Sale of common stock	3	28	36
Equity offering	-	-	332
Payments of medium-term notes	-	-	(82)
Other	5	-	-
Net cash flow (used in) provided by financing activities	(118)	97	167
Net (decrease) increase in cash and cash equivalents	(12)	(17)	32
Cash and cash equivalents at beginning of period	32	49	17
Cash and cash equivalents at end of period	$ 20	$ 32	$ 49
Cash paid during the period for			
Interest (net of allowance for funds used during construction of $3 for the year ended December 31, 2006, and $2 for the years ended December 31, 2005 and 2004, respectively)	$ 108	$ 89	$ 50

Income taxes	37	89	27

See Notes to Consolidated Financial Statements.

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AGL Resources Inc. 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 Securities and Exchange Commission (SEC). For a glossary of key terms and referenced accounting standards, see page 4.

Basis of Presentation

Our consolidated financial statements as of and for the periods ended December 31, 2006, 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.

We currently own a noncontrolling 70% financial interest in SouthStar Energy Services, LLC (SouthStar), and Piedmont Natural Gas Company (Piedmont) owns the remaining 30%. Our 70% interest is noncontrolling because all significant management decisions require approval by both owners. Earnings related to customers in Ohio and Florida are allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our consolidated statements of income and we record Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheets.

We are the primary beneficiary of SouthStar's activities and have determined that SouthStar is a variable interest entity as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities," as revised in December 2003 (FIN 46R). We determined that SouthStar was a variable interest entity 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 Company (Atlanta Gas Light).

Prior to our sale of Saltville Gas Storage Company, LLC (Saltville) in August 2005, we used the equity method to account for and report our 50% interest in Saltville. Saltville was a joint venture with a subsidiary of Duke Energy Corporate to develop a high-deliverability natural gas storage facility in Saltville, Virginia. We used the equity method because we exercised significant influence over but did not control the entity and because we were not the primary beneficiary as defined by FIN 46R.

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. 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 accounts once we deem them to be uncollectible.

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Inventories

For our distribution operations subsidiaries, we record natural gas stored underground at weighted average costs. For Sequent Energy Management, L.P. (Sequent), SouthStar and Jefferson Island Storage & Hub, LLC (Jefferson Island), we account for natural gas inventory at the lower of weighted average cost or market.

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 average cost 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. Consequently, as a result of declining natural gas prices, Sequent recorded adjustments of $43 million and SouthStar recorded adjustments of $6 million in 2006 against cost of sales to reduce the value of their inventories to market value. Sequent recorded a $3 million adjustment in 2005 and a $1 million adjustment in 2004. SouthStar was not required to make similar adjustments in 2005 or in 2004.

For volumes of gas stored by Sequent under park and loan arrangements that are payable or to be repaid at predetermined dates to third parties, Sequent records the inventory at fair value. Materials and supplies inventories are stated at the lower of average cost or market.

In Georgia's competitive environment, Marketers - that is, marketers who are certificated by the Georgia Public Service Commission (Georgia Commission) to sell retail natural gas in Georgia, 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.

Property, Plant and Equipment

A summary of our property, plant and equipment (PP&E) by classification as of December 31, 2006 and 2005 is provided in the following table.

In millions		**2006**		**2005**
Transmission and distribution	$	4,047	$	3,867
Storage		267		209
Other		454		476
Construction work in progress		208		239
Total gross PP&E		4,976		4,791
Accumulated depreciation		(1,540)		(1,458))
Total net PP&E	$	3,436	$	3,333

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 used to finance the construction of major projects and is capitalized in the 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. These include such things as telecommunications conduit, fiber optic cable and other telecommunications equipment and tools.

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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 rate for depreciable property -- excluding transportation equipment for Atlanta Gas Light, Virginia Natural Gas, Inc. (Virginia Natural Gas) and Chattanooga Gas Company (Chattanooga Gas) -- was approximately 2.5% during 2006, 2.6% during 2005 and 2.6% during 2004. The composite, straight-line rate for Elizabethtown Gas, Florida City Gas and Elkton Gas was approximately 3.0 % for 2006, 3.1% during 2005 and 3.25% for December 2004. 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 over a period of 1 to 35 years.

AFUDC

The applicable state regulatory agencies authorize Atlanta Gas Light, Elizabethtown Gas and Chattanooga Gas to record the cost of debt and equity funds as part of the cost of construction projects in our consolidated balance sheets and as AFUDC in the statements of consolidated income. The Georgia Commission has authorized a rate of 8.53%, and the Tennessee Regulatory Authority (Tennessee Commission) has authorized a rate of 7.43%. Effective January 1, 2007, the Tennessee Commission authorized a rate of 7.89%. The New Jersey Board of Public Utilities (New Jersey Commission) has authorized a variable rate based on the Federal Energy Regulatory Commission (FERC) method of accounting for AFUDC. At December 31, 2006 the rate was 5.37%. The total AFUDC for the years ended December 31, 2006, 2005 and 2004 was $5 million, $4 million and $5 million, respectively. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

Goodwill

Statement of Financial Accounting Standards (SFAS) No. 142, “Goodwill and Other Intangible Assets” (SFAS 142), requires us to perform an annual goodwill impairment test. We have included $420 million of goodwill in our consolidated balance sheets as of December 31, 2006, of which $229 million is related to our acquisition of NUI Corporation (NUI) in November 2004; $170 million is related to our acquisition of Virginia Natural Gas in 2000; $14 million is related to our acquisition of Jefferson Island in October 2004; and $7 million is related to our acquisition of Chattanooga Gas in 1988.

We annually assess goodwill for impairment at a reporting unit level which generally equates to our operating segments as discussed in Note 11“Segment Information,” and have not recognized any impairment charges for the years ended December 31, 2006, 2005 and 2004. We also assess goodwill for impairment if events or changes in circumstances may indicate an impairment of goodwill exists. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, we record an impairment loss equal to the excess of the asset’s carrying value over its fair value. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, regulatory and legal proceedings and the periodic regulatory filings for our regulated utilities.

Taxes

Income 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 balance sheets in accordance with SFAS No. 109, “Accounting for Income Taxes” (SFAS 109). Investment tax credits of approximately $18 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.

State and local taxes We collect and remit various taxes on behalf of various governmental authorities. We record these amounts in our consolidated balance sheets 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 distribution operations 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.

Any difference between the billings under the seasonal rate design and the SFV revenue recognized is deferred and reconciled to actual billings on an annual basis. Atlanta Gas Light had unrecovered seasonal rates of approximately $11 million as of December 31, 2006 and $11 million as of December 31, 2005 (included as current assets in the consolidated balance sheets) related to the difference between the billings under the seasonal rate design and the SFV revenue recognized.

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 meter reading date to the end of the accounting period. These are included in the consolidated balance sheets 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 weather normalization adjustments (WNA) that largely 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.

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 balance sheets 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 SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” (SFAS 133), 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.

Cost of Gas

Excluding Atlanta Gas Light, we charge our utility customers for natural gas consumed using purchased gas adjustment (PGA) mechanisms set by the state regulatory agencies. Under the PGA, we defer (that is, include as a current asset or liability in the consolidated balance sheets 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.

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Comprehensive Income

Our comprehensive income includes net income plus other comprehensive income (OCI), which includes other gains and losses affecting shareholders' equity that accounting principles generally accepted in the United States of America (GAAP) excludes from net income. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges and minimum pension liability adjustments. The following table illustrates our OCI activity for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Cash flow hedges:			
Net derivative unrealized gains arising during the period (net of $7, $3 and $3 in taxes)	$ 11	$ 5	$ 6
Less reclassification of realized gains included in income (net of $1, $4 and $1 in taxes)	(1)	(7)	(2)
Over funded (unfunded) pension obligation (net of $7, $3 and $7 in taxes)	11	(5)	(11)
Other (net of tax)	-	-	1
Total	$ 21	$ (7)	$ (6)

Earnings Per Common Share

We compute basic earnings per common share by dividing our income available to common shareholders by the daily weighted average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share 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 performance units and stock options. The future issuance of shares underlying the performance 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. No items are antidilutive. The following table shows the calculation of our diluted earnings per share 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	2006	2005	2004
Denominator for basic earnings per share (1)	77.6	77.3	66.3
Assumed exercise of potential common shares	0.4	0.5	0.7
Denominator for diluted earnings per share	78.0	77.8	67.0

(1) Daily weighted average shares outstanding.

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 regulatory accounting, pipeline replacement program (PRP) accruals, environmental liability accruals, derivative and hedging activities, allowance for contingencies, pension and postretirement obligations, derivative and hedging activities and provision for income taxes. Our actual results could differ from our estimates.

Accounting Developments

FIN 48 In July 2006, the FASB issued SFAS Interpretation No. 48, “Accounting for Uncertainty in Income Taxes - an interpretation of SFAS Statement No. 109” (FIN 48). FIN 48 applies to all “tax positions” accounted for under SFAS 109. FIN 48 refers to “tax positions” as positions taken in a previously filed tax return or positions expected to be taken in a future tax return that are reflected in measuring current or deferred income tax assets and liabilities reported in the financial statements. FIN 48 further clarifies a tax position to include the following:

- a decision not to file a tax return in a particular jurisdiction for which a return might be required,
- an allocation or a shift of income between taxing jurisdictions,
- the characterization of income or a decision to exclude reporting taxable income in a tax return, or
- a decision to classify a transaction, entity, or other position in a tax return as tax exempt.

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FIN 48 clarifies that a tax benefit may be reflected in the financial statements only if it is "more likely than not" that a company will be able to sustain the tax return position, based on its technical merits. If a tax benefit meets this criterion, it should be measured and recognized based on the largest amount of benefit that is cumulatively greater than 50% likely to be realized. This is a change from current practice, whereby companies may recognize a tax benefit only if it is probable a tax position will be sustained.

FIN 48 also requires that we make qualitative and quantitative disclosures, including a discussion of reasonably possible changes that might occur in unrecognized tax benefits over the next 12 months; a description of open tax years by major jurisdictions; and a roll-forward of all unrecognized tax benefits, presented as a reconciliation of the beginning and ending balances of the unrecognized tax benefits on an aggregated basis.

This statement became effective for us on January 1, 2007 and, based on our analysis, FIN 48 does not have a material effect on our consolidated results of operations, cash flows or financial position.

SFAS 157 In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 establishes a framework for measuring fair value and requires expanded disclosures regarding fair value measurements. SFAS 157 does not require any new fair value measurements. However, it eliminates inconsistencies in the guidance provided in previous accounting pronouncements.

SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including financial statements for an interim period within that fiscal year. All valuation adjustments will be recognized as cumulative-effect adjustments to the opening balance of retained earnings for the fiscal year in which SFAS 157 is initially applied. We are currently evaluating the impact that SFAS 157 will have on our consolidated results of operations, cash flows and financial position.

Note 2 - Risk Management

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists of members of senior management and is charged with reviewing and enforcing our risk management activities. Our risk management policies limit the use of derivative financial instruments and physical transactions within predefined risk tolerances associated with pre-existing or anticipated physical natural gas sales and purchases and system use and storage. We use the following derivative financial instruments and physical transactions to manage commodity price, interest rate and weather risks:

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

Interest Rate Swaps

To maintain an effective capital structure, our policy is to borrow funds using a mix of fixed-rate and variable-rate debt. We entered into interest rate swap agreements for the purpose of managing the interest rate risk associated with our fixed-rate and variable-rate debt obligations. We designated these interest rate swaps as fair value hedges in accordance with SFAS 133. We record the gain or loss on fair value hedges in earnings in the period of change, together with the offsetting loss or gain on the hedged item attributable to the risk being hedged.

As of December 31, 2006, a notional principal amount of $100 million of these interest rate swap agreements effectively converted the interest expense associated with a portion of our senior notes from fixed rates to variable rates based on an interest rate equal to the London Interbank Offered Rate (LIBOR), plus a spread determined at the swap date. The floating rate swap range for our interest rate swaps for the year ended December 31, 2006, was 9.0%.

Commodity-related Derivative Instruments

Elizabethtown Gas In accordance with a directive from the New Jersey Commission, Elizabethtown Gas enters into derivative transactions to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative transactions are marked to market each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. As of December 31, 2006, Elizabethtown Gas had entered into New York Mercantile Exchange (NYMEX) futures contracts to purchase approximately 8.55 Bcf of natural gas. Approximately 81% of these contracts have a duration of one year or less, and none of these contracts extends beyond October 2008.

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Sequent We are exposed to risks associated with changes in the market price of natural gas. Sequent uses derivative financial instruments to reduce our exposure to the risk of changes in the prices of natural gas. The fair value of these derivative financial instruments 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 financial instruments we use.

We mitigate substantially all the commodity price risk associated with Sequent's natural gas portfolio by locking in the economic margin at the time we enter into natural gas purchase transactions for our stored natural gas. 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 profit margin. We use NYMEX futures contracts and other over-the-counter derivatives to sell natural gas at that future price to substantially lock in the profit margin we will ultimately realize when the stored gas is actually sold. These futures contracts meet the definition of derivatives under SFAS 133 and are recorded at fair value and marked to market in our consolidated balance sheets, with changes in fair value recorded in earnings in the period of change. 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 mark-to-market basis we utilize for the derivatives used to mitigate the commodity 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.

At December 31, 2006, Sequent's commodity-related derivative financial instruments represented purchases (long) of 607 Bcf and sales (short) of 614 Bcf with approximately 94% of these instruments are scheduled to mature in less than two years and the remaining 6% in three to nine years. At December 31, 2006, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $133 million and a liability of $14 million. Sequent 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 $132 million during 2006, $30 million of unrealized losses during 2005 and unrealized gains of $22 million during 2004.

SouthStar Commodity-related derivative financial instruments (futures, options and swaps) are used by SouthStar to manage exposures arising from changing commodity prices. SouthStar's objective for holding these derivatives is to utilize the most effective method to reduce or eliminate the impact of this exposure. We have designated a portion of SouthStar's derivative transactions as cash flow hedges under SFAS 133. 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. 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 statement of consolidated income in the period in which it occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

At December 31, 2006, the fair values of these derivatives were reflected in our consolidated financial statements as a current asset of $28 million and a current liability of $12 million. For those open derivatives with maturity dates beyond December 31, 2007, the fair value of these derivatives are reflected as a long-term asset of $2 million in our consolidated financial statements. The maximum maturity of open positions is less than two years, with those positions greater than one year, but less than two years representing a net position of 0.2 Bcf.

SouthStar also enters into both exchange and over-the-counter derivative transactions to hedge commodity price risk. Credit risk is mitigated for exchange transactions through the backing of the NYMEX member firms. For over-the-counter transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2006, SouthStar's maximum exposure to any single over-the-counter counterparty was $7 million.

Weather Derivatives

In September 2006, SouthStar entered into weather derivative contracts as an economic hedge of operating margins in the event of warmer-than-normal weather in the current heating season, primarily from November 2006 through March 2007. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of Emerging Issues Task Force Issue No. 99-02, "Accounting for Weather Derivatives." SouthStar had no weather derivatives outstanding as of December 31, 2005 or 2004. As of December 31, 2006, SouthStar recorded a receivable of $7 million for this hedging activity.

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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 11 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 a minimum of 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 customers. This credit risk is measured by 30-day receivable exposure plus forward exposure, which is generally concentrated in 20 of its customers. Sequent evaluates the credit risk of its customers using a Standard & Poor's Ratings Services (S&P) equivalent credit rating, which is determined by a process of converting the lower of the S&P or Moody's Investors Service (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, 2006, Sequent's top 20 customers represented approximately 57% of the total credit exposure of $394 million, derived by adding together the top 20 customers' exposures and dividing by the total of Sequent's counterparties' exposures. Sequent's customers or the customers' guarantors had a weighted average S&P equivalent rating of A- at December 31, 2006.

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.

All activities associated with price risk management activities and derivative instruments are included as a component of cash flows from operating activities in our consolidated statements of cash flows. Our derivatives not designated as hedges under SFAS 133, included in operating cash flows for the years ended December 31, 2006, 2005, and 2004 were $(128) million, $36 million, and $(22) million, respectively.

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Note 3 - Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71). Our regulatory assets and liabilities, and associated liabilities for our unrecovered PRP costs, unrecovered environmental remediation costs (ERC) and the associated assets and liabilities for our Elizabethtown Gas hedging program, are summarized in the table below.

	December 31,	
In millions	2006	2005
Regulatory assets		
Unrecovered PRP costs	$ 274	$ 303
Unrecovered ERC	170	196
Elizabethtown Gas hedging program	16	-
Unrecovered postretirement benefit costs	13	14
Unrecovered seasonal rates	11	11
Unrecovered PGA	14	8
Other	13	10
Total regulatory assets	511	542
Associated assets		
Elizabethtown Gas hedging program	-	17
Total regulatory and associated assets	$ 511	$ 559
Regulatory liabilities		
Accumulated removal costs	$ 162	$ 156
Elizabethtown Gas hedging program	-	17
Unamortized investment tax credit	18	19
Deferred PGA	24	40
Regulatory tax liability	22	17
Other	10	6
Total regulatory liabilities	236	255
Associated liabilities		
PRP costs	237	265
ERC	87	88

Elizabethtown Gas Hedging Program		16		-
Total associated liabilities		340		353
Total regulatory and associated liabilities	$	576	$	608

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 SFAS 71 were no longer applicable, we would recognize a write-off of net regulatory assets (regulatory assets less regulatory liabilities) that would result in a charge to net income, and classified as an extraordinary item. 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 SFAS 71 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.

All the regulatory assets included in the table above are included in base rates except for the unrecovered PRP costs, unrecovered ERC and the deferred PGA, which are recovered through specific rate riders on a dollar for dollar basis. The rate riders that authorize recovery of unrecovered PRP costs and the deferred PGA 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's hedging program asset reflects unrealized losses that will be recovered through the PGA on a dollar for dollar basis, once the losses are realized. Unrecovered postretirement benefit costs are recoverable through base rates over the next 7 to 26 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.

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.

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Pipeline Replacement Program

Atlanta Gas Light The PRP, ordered by the Georgia Commission to be administered by Atlanta Gas Light, requires, among other things, that Atlanta Gas Light replace all bare steel and cast iron pipe in its system in the state of Georgia within a 10-year period beginning October 1, 1998. Atlanta Gas Light identified, and provided notice to the Georgia Commission of 2,312 miles of pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 320 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it will be assessed certain nonperformance penalties. October 1, 2006 marked the beginning of the ninth year of the 10-year PRP.

The order also 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

On June 10, 2005, Atlanta Gas Light and the Georgia Commission entered into a Settlement Agreement that, among other things, extends Atlanta Gas Light's PRP by five years to require that all replacements be completed by December 2013. The timing of replacements was subsequently specified in an amendment to the PRP stipulation. This amendment, which was approved by the Georgia Commission on December 20, 2005, requires Atlanta Gas Light to replace all cast iron pipe and 70% of all bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013.

Under the Settlement Agreement, base rates charged to customers will remain unchanged through April 30, 2010, but Atlanta Gas Light will recognize reduced base rate revenues of $5 million on an annual basis through April 30, 2010. The five-year total reduction in recognized base rate revenues of $25 million will be applied to the allowed amount of costs incurred to replace pipe, which will reduce the amounts recovered from customers under the PRP rider. The Settlement Agreement also set the per customer fixed PRP rate that Atlanta Gas Light will charge at $1.29 per customer per month from May 2005 through September 2008 and at $1.95 from October 2008 through December 2013 and includes a provision that allows for a true-up of any over- or under-recovery of PRP revenues that may result from a difference between PRP charges collected through fixed rates and actual PRP revenues recognized through the remainder of the program.

The Settlement Agreement also allows Atlanta Gas Light to recover through the PRP $4 million of the $32 million capital costs associated with its purchase of 250 miles of pipeline in central Georgia from Southern Natural Gas Company, a subsidiary of El Paso Corporation. The remaining capital costs are included in Atlanta Gas Light's rate base and collected through base rates.

Atlanta Gas Light has recorded a long-term regulatory asset of $247 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 $27 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:

- $27 million in 2006
- $26 million in 2005

- $28 million in 2004

As of December 31, 2006, Atlanta Gas Light had recorded a current liability of $35 million, representing expected program expenditures for the next 12 months and a long-term liability of $202 million, representing expected program expenditures starting in 2008 through the end of the program in 2013.

Atlanta Gas Light capitalizes and depreciates the capital expenditure costs incurred from the PRP 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 PRP 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.

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Elizabethtown Gas In August 2006, the New Jersey Commission issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8” cast iron main pipes and any unanticipated 10”-12” cast iron main pipes integral to the replacement of the 8” main pipes. The order allows Elizabethtown Gas to recognize revenues under a deferred recovery mechanism for costs to replace the pipe that exceeds a baseline amount of $3 million. The term of the stipulation is from the date of the order through December 31, 2008. Total replacement costs through December 31, 2008 are expected to be $10 million, of which $7 million will be eligible for the deferred recovery mechanism. Revenues recognized and deferred for recovery under the stipulation are estimated to be approximately $1 million. All costs incurred under the program will be included in Elizabethtown Gas’ next rate case to be filed in 2009.

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.

Atlanta Gas Light The presence of coal tar and certain other byproducts of a natural gas manufacturing process used to produce natural gas prior to the 1950s has been identified at or near 10 former Atlanta Gas Light operating sites in Georgia and at 3 sites of predecessor companies in Florida. Atlanta Gas Light has active environmental remediation or monitoring programs in effect at 10 of these sites. Two sites in Florida are currently in the investigation or preliminary engineering design phase, and one Georgia site has been deemed compliant with state standards.

Atlanta Gas Light has customarily reported estimates of future remediation costs for these former sites based on probabilistic models of potential costs. These estimates are reported on an undiscounted basis. As cleanup options and plans mature and cleanup contracts are entered into, Atlanta Gas Light is better able to provide conventional engineering estimates of the likely costs of remediation at its former sites. These estimates contain various engineering uncertainties, but Atlanta Gas Light continuously attempts to refine and update these engineering estimates.

Atlanta Gas Light’s current estimate for the remaining cost of future actions at its former operating sites is $27 million, a reduction of $4 million over 2005, which may change depending on whether future measures for groundwater will be required.

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 Atlanta Gas Light may be held liable but for which it cannot reasonably estimate an amount. As of December 31, 2006, the remediation expenditures expected to be incurred over the next 12 months are reflected as a current liability of $13 million.

The ERC liability is included as a corresponding regulatory asset, which is a combination of accrued ERC and unrecovered cash expenditures for investigation and cleanup costs. Atlanta Gas Light has three ways of recovering investigation and cleanup costs. First, the Georgia Commission has approved an ERC recovery rider. The ERC recovery mechanism allows for recovery of expenditures over a five-year period subsequent to the period in which the expenditures are incurred. Atlanta Gas Light expects to collect $26 million in revenues over the next 12 months under the ERC recovery rider, which is reflected as a current asset. The amounts recovered from the ERC recovery rider during the last three years were

- $29 million in 2006
- $28 million in 2005
- $25 million in 2004

The second way to recover costs is by exercising the legal rights Atlanta Gas Light believes it has to recover a share of its costs from other potentially responsible parties, typically former owners or operators of these sites. There were no material recoveries from potentially responsible parties during 2006, 2005 or 2004.

The third way to recover costs is from the receipt of net profits from the sale of remediated property. There was one sale of property during 2006.

Elizabethtown Gas In New Jersey, Elizabethtown Gas is currently conducting remediation activities with oversight from the New Jersey Department of Environmental Protection. Although we cannot estimate the actual total cost of future environmental investigation and remediation efforts with precision, based on probabilistic models similar to those used at Atlanta Gas Light's former operating sites, the range of reasonably probable costs is $60 million to $118 million. As of December 31, 2006, we have recorded a liability equal to the low end of that range, or $60 million, of which $6 million in expenditures are expected to be incurred over the next 12 months.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the New Jersey Commission to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $65 million, inclusive of interest, as of December 31, 2006, reflecting the future recovery of both incurred costs and accrued carrying charges. Elizabethtown Gas expects to collect $1 million in revenues over the next 12 months. Elizabethtown Gas has also been successful in recovering a portion of remediation costs incurred in New Jersey from its insurance carriers and continues to pursue additional recovery.

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Note 4 - Employee Benefit Plans

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.

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 June 2010, at which time any of those participants who are still active will accrue future benefits under the career average earnings formula.

The NUI Retirement Plan covers substantially all of NUI's employees who were employed on or before December 31, 2005, except Florida City Gas union employees, who participate in a union-sponsored multiemployer plan. Pension benefits are based on years of credited service and final average compensation.

Effective with our acquisition of NUI in November 2004, we became sponsor of the NUI Retirement Plan. Throughout 2005, we maintained existing benefits for NUI employees, including participation in the NUI Retirement Plan. Beginning in 2006, eligible participants in the NUI Retirement Plan became eligible to participate in the AGL Retirement Plan and the benefits of those participants under the NUI Retirement Plan were frozen as of December 31, 2005, resulting in a $15 million reduction to the NUI Retirement Plan's projected benefit obligation as of December 31, 2005. Participants in the NUI Retirement Plan have the option of receiving a lump sum distribution upon retirement for all benefits earned through December 31, 2005. This resulted in settlement payments of $12 million and an immaterial settlement loss. This option is not permitted under the AGL Retirement Plan, except for accrued benefits valued at less than $10,000.

SFAS 158 In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS 158). We adopted SFAS 158 prospectively on December 31, 2006. SFAS 158 requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits. This statement requires that we quantify the plans' funding status as an asset or a liability on our consolidated balance sheets.

SFAS 158 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 SFAS No. 87, "Employers' Accounting for Pensions," or SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions."

Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2006, we reported a gain to our OCI of $11 million, a decrease of $18 million to accrued pension obligations and an increase of $7 million to accumulated deferred income taxes. Our adoption of SFAS 158 on December 31, 2006, had no impact on our earnings. The following tables present details about our pension plans.

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In millions	AGL Retirement Plan Dec, 31, 2006	AGL Retirement Plan Dec. 31, 2005	NUI Retirement Plan Dec. 31, 2006	NUI Retirement Plan Dec. 31, 2005
Change in benefit obligation				
Benefit obligation at beginning of year	$ 359	$ 340	$ 105	$ 144
Service cost	7	6	-	4
Interest cost	20	19	5	8
Plan amendments	-	-	-	(15)
Settlement loss	-	-	1	-
Settlement payments	-	-	(12)	-
Actuarial loss (gain)	2	14	(7)	(4)
Benefits paid	(20)	(20)	(6)	(32)
Benefit obligation at end of year	$ 368	$ 359	$ 86	$ 105
Change in plan assets				
Fair value of plan assets at beginning of year	$ 286	$ 279	$ 85	$ 111
Actual return on plan assets	31	21	4	6
Employer contribution	6	6	1	-
Settlement payments	-	-	(12)	-
Benefits paid	(20)	(20)	(6)	(32)
Fair value of plan assets at end of year	$ 303	$ 286	$ 72	$ 85
Reconciliation of funded status (1)				
Plan assets less than benefit obligation at end of year	$ (65)	$ (73)	$ (14)	$ (20)
Unrecognized net loss	-	119	-	4
Unrecognized prior service benefit	-	(10)	-	(15)
(Prepaid) accrued pension cost (2)	$ (65)	$ 36	$ (14)	$ (31)
Amounts recognized in the statement of financial position consist of				
Prepaid benefit cost	$ -	$ 42	$ -	$ -
Accrued benefit liability	(65)	(7)	(14)	(31)
Accumulated OCI	-	(92)	-	-
Net amount recognized at year end (3)	$ (65)	$ (57)	$ (14)	$ (31)

(1) After adoption of SFAS 158 on December 31, 2006, these amounts are recorded and this reconciliation is no longer required.

(2) The prepaid pension cost for the NUI Retirement Plan at December 31, 2005 was adjusted for terminations and settlement of liabilities for participants affected by our acquisition of NUI in November 2004. In 2005, we recorded the associated $9 million reduction in our benefit obligation as a reduction to goodwill.

(3) As of December 31, 2006, the AGL Retirement Plan had current liabilities of $1 million, noncurrent liabilities of $64 million and no noncurrent assets. The NUI Retirement Plan had $14 million of noncurrent liabilities and no noncurrent assets or current liabilities.

The accumulated benefit obligation (ABO) and other information for the AGL Retirement Plan and the NUI Retirement Plan are set forth in the following table.

	AGL Retirement Plan		NUI Retirement Plan	
In millions	Dec. 31, 2006	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2005
Projected benefit obligation	$ 368	$ 359	$ 86	$ 105
ABO	352	343	86	105
Fair value of plan assets	303	286	72	85
Increase in minimum liability included in OCI	13	8	-	-
Components of net periodic benefit cost				
Service cost	$ 7	$ 6	$ -	$ 4
Interest cost	20	19	5	8
Expected return on plan assets	(24)	(24)	(7)	(9)
Net amortization	(1)	(1)	(1)	-
Recognized actuarial loss	9	7	-	-
Net annual pension cost	$ 11	$ 7	$ (3)	$ 3

There were no other changes in plan assets and benefit obligations recognized for the AGL and NUI Retirement Plans for the year ended December 31, 2006.

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The 2007 estimated OCI amortization and expected refunds for the AGL and NUI Retirement Plans are set forth in the following table.

	Retirement Plan	
In millions	AGL	NUI
Amortization of transition obligation	$-	$-
Amortization of prior service cost	(1)	(1)
Amortization of net loss	6	-
Refunds expected	-	-

The effects of SFAS 158, including the additional minimum liability (AML) adjustments, for the AGL Retirement Plan and the NUI Retirement Plan are set forth in the following table.

	AGL Retirement Plan				
In millions	Pre-SFAS 158 without AML adjustment	AML adjustment	Pre-SFAS 158 with AML adjustment	SFAS 158 adoption adjustments	Post-SFAS 158
Prepaid pension asset/ (accrued pension liability)	$ 30	$ (79)	$ (49)	$ (16)	$ (65)
Intangible Asset	-	-	-	-	-
Deferred tax asset	-	30	30	6	36
OCI - pension, net of tax	-	49	49	10	59
OCI - pension, pre-tax	-	79	79	16	95
	NUI Retirement Plan				
In millions	Pre-SFAS 158 without AML adjustment (1)	AML adjustment (1)	Pre-SFAS 158 with AML adjustment (1)	SFAS 158 adoption adjustments	Post-SFAS 158
Prepaid pension asset/ (accrued pension liability)	$ (27)	$ -	$ (27)	$ 13	$ (14)
Intangible Asset	-	-	-	-	-
Deferred tax asset	-	-	-	(5)	(5)
OCI -- pension, net of tax	-	-	-	(8)	(8)
OCI -- pension, pre-tax	-	-	-	(13)	(13)

(1) Values represent amounts less than $1 million.

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations at December 31.

	AGL and NUI Retirement Plans	
	2006	2005
Discount rate	5.8%	5.5%
Rate of compensation increase	4.0%	4.0%

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.

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The following tables present the assumed weighted average discount rate, expected return on plan assets and rate of compensation increase used to determine net periodic benefit cost at the beginning of the period, which was January 1.

	AGL Retirement Plan		
	2006	2005	2004
Discount rate	5.5%	5.8%	6.3%
Expected return on plan assets	8.8%	8.8%	8.8%
Rate of compensation increase	4.0%	4.0%	4.0%

	NUI Retirement Plan		
	2006	2005	2004
Discount rate	5.5%	5.8%	5.8%
Expected return on plan assets	8.8%	8.5%	8.5%
Rate of compensation increase	-%	4.0%	4.0%

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 our actuaries model and our own payment stream based on these indices to develop our rate. Consequently, we selected a discount rate of 5.8% as of December 31, 2006, following our review of these various factors.

Our actual retirement plans' weighted average asset allocations at December 31, 2006 and 2005 and our target asset allocation ranges are as follows.

	Target Range Asset Allocation	AGL Retirement Plan 2006	AGL Retirement Plan 2005
Equity	30%-80%	67%	66%
Fixed income	10%-40%	25%	25%
Real estate and other	10%-35%	8%	8%
Cash	0%-10%	0%	1%

	Target Range Asset Allocation	NUI Retirement Plan 2006	NUI Retirement Plan 2005
Equity	30%-80%	68%	88%
Fixed income	10%-40%	26%	12%
Real estate and other	10%-35%	3%	-%
Cash	0%-10%	3%	-%

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 plans that aims to preserve the retirement plans' capital and maximize investment earnings in excess of inflation within acceptable levels of capital market volatility. To accomplish this goal, the retirement plans' assets are actively managed to optimize long-term return while maintaining a high standard of portfolio quality and proper diversification.

The Policy's risk management strategy establishes a maximum tolerance for risk in terms of volatility to be measured at 75% of the volatility experienced by the S&P 500. We will continue to diversify retirement plan investments to minimize the risk of large losses in a single asset class. 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. The asset mix of these permissible investments is maintained within the Policy's target allocations as included in the preceding tables, but the Committee can vary allocations between various classes or investment managers in order to improve investment results.

Equity market performance and corporate bond rates have a significant effect on our reported unfunded ABO, as the primary factors that drive the value of our unfunded ABO 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 a calculated value and differs from the actual market value of plan assets. The MRVPA 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.

Our employees do not contribute to the retirement plans. We fund the 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. We calculate the minimum amount of funding using the projected unit credit cost method. The Pension Protection Act (the Act) of 2006 contains new funding requirements for single employer defined benefit pension plans. The Act establishes a 100% funding target for plan years beginning after December 31, 2007. However, a delayed effective date of 2011 may apply if the pension plan meets the following targets: 92% funded in 2008; 94% funded in 2009; and 96% funded in 2010. In October 2006 we made a voluntary contribution of $5 million to the AGL Resources Inc. Retirement Plan. No contribution is required for the qualified plans in 2007.

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Postretirement Benefits

Until January 1, 2006, we sponsored two defined benefit postretirement health care plans for our eligible employees, the AGL Resources Inc. Postretirement Health Care Plan (AGL Postretirement Plan) and the NUI Corporation Postretirement Health Care Plan (NUI Postretirement Plan), which we acquired upon our acquisition of NUI. Eligibility for these benefits is based on age and years of service.

The NUI Postretirement Plan provided certain medical and dental health care benefits to retirees, other than retirees of Florida City Gas, depending on their age, years of service and start date. The NUI Postretirement Plan was contributory, and NUI funded a portion of these future benefits through a Voluntary Employees' Beneficiary Association. Effective July 2000, NUI no longer offered postretirement benefits other than pension for any new hires. In addition, NUI capped its share of costs at $500 per participant per month for retirees under age 65, and at $150 per participant per month for retirees over age 65. At the beginning of 2006, eligible participants in the NUI Postretirement Plan became eligible to participate in the AGL Postretirement Plan and all participation in this plan ceased, effective January 1, 2006.

The AGL Postretirement Plan covers all eligible AGL Resources employees who were employed as of June 30, 2002, if they reach retirement age while working for us. 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 $13 million as of December 31, 2006 and $14 million as of December 31, 2005. In addition, we recorded a regulatory liability of $4 million as of December 31, 2006 and $3 million as of December 31, 2005 for our expected expenses under the AGL Postretirement Plan. We expect to pay $7 million of insurance claims for the postretirement plan in 2007, 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.

On July 1, 2004, the AGL Postretirement Plan was amended to remove prescription drug coverage for Medicare-eligible retirees effective January 1, 2006. Certain grandfathered NUI retirees participating in the NUI Postretirement Plan will continue receiving a prescription drug benefit through some period of time.

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The following table presents details about our postretirement benefits.

In millions	AGL Postretirement Plan Dec. 31, 2006	AGL Postretirement Plan Dec. 31, 2005	NUI Postretirement Plan Dec. 31, 2005
Change in benefit obligation			
Benefit obligation at beginning of year (1)	$ 107	$ 98	$ 23
Service cost	1	1	-
Interest cost	5	5	1
Plan amendments	-	-	(7)
Actuarial (gain) loss	(9)	(6)	1
Benefits paid	(9)	(9)	(2)
Benefit obligation at end of year	$ 95	$ 89	$ 16
Change in plan assets			
Fair value of plan assets at beginning of year	$ 59	$ 49	$ 9
Actual return on plan assets	5	4	-
Employer contribution	8	6	2
Benefits paid	(9)	(9)	(2)
Fair value of plan assets at end of year	$ 63	$ 50	$ 9
Reconciliation of funded status			
Plan assets less benefit obligation at end of year	$ (32)	$ (39)	$ (7)
Unrecognized loss	-	22	2
Unrecognized transition amount	-	1	-
Unrecognized prior service benefit	-	(23)	(6)
Accrued benefit cost (2)	$ (32)	$ (39)	$ (11)
Amounts recognized in the statement of financial position consist of			
Prepaid benefit cost	$ -	$ -	$ -
Accrued benefit liability	(32)	(39)	(11)
Accumulated OCI	-	-	-
Net amount recognized at year end (3)	$ (32)	$ (39)	$ (11)

(1) The NUI Postretirement Plan was terminated and eligible former participants became eligible to participate in the AGL Postretirement Plan on January 1, 2006.

(2) After adoption of SFAS 158 on December 31, 2006 these amounts are recorded and this reconciliation is no longer required.

(3) As of December 31, 2006, the AGL Postretirement Plan had $32 million of noncurrent liabilities and no noncurrent assets or current liabilities.

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The following tables present details on the components of our net periodic benefit cost for the AGL Postretirement Plan and the NUI Postretirement Plan at the balance sheet dates.

	AGL Postretirement Plan	
In millions	2006	2005
Service cost	$ 1	$ 1
Interest cost	5	5
Expected return on plan assets	(4)	(4)
Amortization of prior service cost	(4)	(3)
Recognized actuarial loss	1	1
Net periodic postretirement benefit cost	$ (1)	$ -

	NUI Postretirement Plan (1)
In millions	2005
Service cost	$ -
Interest cost	1
Expected return on plan assets	-
Amortization of prior service cost	(1)
Recognized actuarial loss	-
Net periodic postretirement benefit cost	$ -

(1) The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL Postretirement Plan on January 1, 2006.

There were no other changes in plan assets and benefit obligations recognized for the AGL and NUI Postretirement Plans for the year ended December 31, 2006. The 2007 estimated OCI amortization and refunds expected for the AGL Postretirement Plan are set forth in the following table.

In millions	2007
Amortization of transition obligation	$-
Amortization of prior service cost	(4)
Amortization of net loss	1
Refunds expected	-

The effects of SFAS 158 and AML adjustments for the AGL Postretirement Plan are set forth in the following table.

	AGL Postretirement Plan				
In millions	Pre-SFAS 158 without AML adjustment	AML adjustment	Pre-SFAS 158 with AML adjustment	SFAS 158 adoption adjustments	Post -SFAS 158

Prepaid pension asset/ (accrued pension liability)	$ (40)	$ -	$ (40)	$ 8	$ (32)
Intangible Asset	-	-	-	-	-
Deferred tax asset	-	-	-	(3)	(3)
OCI - pension, net of tax	-	-	-	(5)	(5)
OCI - pension, pre-tax	-	-	-	(8)	(8)

The following table sets forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations for the AGL and NUI postretirement plans at December 31.

	AGL	AGL	NUI
	2006	2005	2005 (1)
Discount rate	5.8%	5.5%	5.5%
Rate of compensation increase	4.0%	4.0%	-%

(1) The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

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The following tables present our weighted average assumed rates used to determine benefit obligations at the beginning of the period, January 1 for the AGL Postretirement Plan and December 1 for the NUI Postretirement Plan, and our weighted average assumed rates used to determine net periodic benefit cost at the beginning of these same periods.

	AGL Postretirement Plan		
	2006 (1)	2005	2004
Discount rate - benefit obligation	5.8%	5.5%	5.8%
Discount rate - net periodic benefit cost	5.5 %	5.8 %	6.3 %
Expected return on plan assets	8.5%	8.8%	8.8%
Rate of compensation increase	4.0%	4.0%	4.0%

	NUI Postretirement Plan (1)	
	2005	2004
Discount rate - benefit obligation	5.5%	5.8%
Discount rate - net periodic benefit cost	5.8%	5.8 %
Expected return on plan assets	3.0%	2.0%
Rate of compensation increase	-%	-%

(1) The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

For information on the discount rate assumptions used for our postretirement plans, see the discussion contained in this Note 4 under the caption “Pension Benefits.“

We consider the same factors in determining and selecting our assumptions for the overall expected long-term rate of return on plan assets as those considered in determining and selecting the overall expected long-term rate of return on plan assets for our retirement plans. For purposes of measuring our accumulated postretirement benefit obligation, the assumed pre-Medicare and post-Medicare health care inflation rates are as follows

	AGL Postretirement Plan			
	Pre-medicare cost (pre-65 years old)		Post-medicare cost (post-65 years old)	
Assumed health care cost trend rates at December 31,	2006	2005	2006	2005
	2.5%	2.5%	2.5%	2.5%

Health care costs trend rate assumed for next year				
Rate to which the cost trend rate gradually declines	2.5%	2.5%	2.5%	2.5%
Year that the rate reaches the ultimate trend rate	N/A	N/A	N/A	N/A

	NUI Postretirement Plan (1)
Assumed health care cost trend rates at December 31,	2005
Health care costs trend rate assumed for next year	2.5%
Rate to which the cost trend rate gradually declines	2.5%
Year that the rate reaches the ultimate trend rate	N/A

(1) The NUI postretirement plan was terminated and eligible former participants became eligible to participate in the AGL postretirement plan on January 1, 2006.

Effective January 2006, our health care trend rates for both the AGL Postretirement Plan and the NUI Postretirement Plan were capped at 2.5%. This cap limits the increase in our contributions to the annual change in the consumer price index (CPI). An annual CPI rate of 2.5% was assumed for future years.

Assumed health care cost trend rates impact the amounts reported for our health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effects for the AGL Postretirement Plan and the NUI Postretirement Plan.

	AGL Postretirement Plan One-Percentage-Point	
In millions	Increase	Decrease
Effect on total of service and interest cost	$ -	$ -
Effect on accumulated postretirement benefit obligation	4	(4)

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Our investment policies and strategies for our postretirement plans, including target allocation ranges, are similar to those for our retirement plans. We fund the plans annually; retirees contribute 20% of medical premiums, 50% of the medical premium for spousal coverage and 100% of the dental premium. Our postretirement plans' weighted average asset allocations for 2006 and 2005 and our target asset allocation ranges are as follows.

In millions	Target Asset allocation ranges	2006	2005
Equity	30%-80%	66%	52%
Fixed income	10%-40%	32%	46%
Real estate and other	10%-35%	-%	1%
Cash	0%-10%	2%	1%

The following table presents expected benefit payments covering the periods 2007 through 2016 for our retirement plans and postretirement health care plans. There will be benefit payments under these plans beyond 2016.

For the years ended Dec. 31, *(in millions)*	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
2007	$ 20	$ 7	$ 7
2008	20	6	7
2009	20	6	7
2010	20	6	7
2011	20	6	7
2012-2016	111	32	35

The following table presents the amounts not yet reflected in net periodic benefit cost and included in accumulated OCI as of December 31, 2006.

In millions	AGL Retirement Plan	NUI Retirement Plan	AGL Postretirement Plan
Transition asset	$ -	$ -	$ 1
Prior service credit	(9)	(14)	(25)
Net gain	104	1	16
Accumulated OCI	95	(13)	(8)
Net amount recognized in statement of financial position.	(65)	(14)	(32)
Cumulative employer contributions in excess of net periodic benefit cost (accrued) prepaid	$ 30	$ (27)	$ (40)

There were no other changes in plan assets and benefit obligations recognized in the AGL and NUI Retirement Plans or the AGL Postretirement Plan for the year ended December 31, 2006.

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 in the following amounts:

- $6 million in 2006
- $5 million in 2005
- $5 million in 2004

We also sponsor the Nonqualified Savings Plan (NSP), an unfunded, nonqualified plan similar to the RSP. The NSP provides an opportunity for eligible employees who could reach the maximum contribution amount in the RSP to contribute additional amounts for retirement savings. Our contributions to the NSP have not been significant in any year.

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Note 5 - Stock-based and Other Incentive Compensation Plans

Stock-based Compensation Plans and Agreements

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

- The Long-Term Incentive Plan (1999) (LTIP) provides for the grant of incentive and nonqualified stock options, performance units and shares of restricted stock to key employees. The LTIP authorizes the issuance of up to 9.5 million shares of our common stock, of which 5,826,584 shares were available for issuance as of December 31, 2006. If our shareholders approve the 2007 Omnibus Performance Incentive Plan (the 2007 Plan) at the 2007 annual meeting of shareholders (Proposal 2 to our proxy statement), no further grants will be made under the LTIP except for reload options granted under the plan's outstanding options. This means that if the shareholders approve the 2007 Plan, approximately 2.3 million shares (representing the number of outstanding options under the LTIP as of December 31, 2006) will be available for issuance under the LTIP.
- A predecessor plan, the Long-Term Stock Incentive Plan (LTSIP), provides for the grant of incentive and nonqualified stock options, shares of restricted stock and stock appreciation rights (SARs) to key employees. Following shareholder approval of the LTIP, no further grants have been made under the LTSIP.
- The Officer Incentive Plan (Officer Plan) provides for the grant of nonqualified stock options and shares of restricted stock to new-hire officers. The Officer Plan authorizes the issuance of up to 600,000 shares of our common stock, of which 313,433 shares were available for issuance as of December 31, 2006.
- SARs have been granted to key employees under individual agreements that permit the holder to receive cash in an amount equal to the difference between the fair market value of a share of our common stock on the date of exercise and the SAR base value. A total of 26,863 SARs at a weighted average exercise price of $24.24 were vested and outstanding as of December 31, 2006. We recognize the intrinsic value of the SARs as compensation expense over the vesting period. Compensation expense for 2006, 2005 and 2004 was not material to the statement of operations.
- The 2006 Non-Employee Directors Equity Compensation Plan (2006 Directors Plan) provides for the grant of stock to non-employee directors as payment of their annual retainer and stock award upon initial election or appointment to the Board of Directors. The 2006 Directors Plan authorizes the issuance of up to 200,000 shares of our common stock, of which 200,000 shares were available for issuance as of December 31, 2006.
- A predecessor plan, the 1996 Non-Employee Directors Equity Compensation Plan (1996 Directors Plan) originally provided for the grant of nonqualified stock options and stock to non-employee directors as payment of their annual retainer and stock award upon initial election or appointment to the Board of Directors. In December 2002, the 1996 Directors Plan was amended to eliminate the granting of stock options. As a result, the 1996 Directors Plan now provides solely for the issuance of our common stock. The 1996 Directors Plan authorizes the issuance of up to 200,000 shares of our common stock, of which 59,241 shares were available for issuance as of December 31, 2006.
- The Employee Stock Purchase Plan (ESPP) is a nonqualified, broad-based employee stock purchase plan for eligible employees. The ESPP authorizes the issuance of up to 600,000 shares of our common stock, of which 440,458 shares were available for issuance as of December 31, 2006.

Effective January 1, 2006, we adopted SFAS 123(R), using the modified prospective application transition method; accordingly, financial results for the prior periods presented were not retroactively adjusted to reflect the effects of SFAS 123R.

Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with SFAS No. 123, as amended by SFAS No. 148, "Accounting for Stock-Based Compensation- Transition and Disclosure." This allowed us to follow APB 25 and related interpretations in accounting for our stock-based compensation plans under the intrinsic value method.

SFAS 123R 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 share-based awards, which include performance shares and stock options. Performance share awards contain market conditions. Both performance share and stock option awards contain a service condition. In accordance with SFAS 123R, 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.

In 2004 and 2005, we did not record compensation expense related to our stock option grants in our financial statements, which is consistent with the APB 25 requirements. However, at the end of each reporting period, we recorded compensation expense over the requisite service period for our other stock-based and cash unit awards. The following table provides additional information on compensation costs and income tax benefits related to our compensation awards. We recorded these amounts in our consolidated statements of income for the years ended December 31, 2006, 2005 and 2004.

In millions	2006	2005	2004
Compensation costs	$ 9	$ 5	$ 7
Income tax benefits	3	8	5

Prior to our adoption of SFAS 123R, benefits of tax deductions in excess of recognized compensation costs were reported as operating cash flows. SFAS 123R requires excess tax benefits to be reported as a financing cash inflow rather than as a reduction of taxes paid. For the year ended December 31, 2006, our cash flow for financing activities included an immaterial amount for benefits of tax deductions in excess of recognized compensation costs. For 2005 and 2004, we included $8 million and $5 million, respectively, of such benefits in cash flow provided by operating activities.

If stock-based compensation expense for the years ended December 31, 2004 and 2005 had been recorded based on the fair value of the awards at the grant dates consistent with the method prescribed by SFAS 123, which has been superseded by SFAS 123R, our net income and earnings per share for the years ended December 31, 2004 and 2005 would have been reduced to the amounts shown in the following table,

In millions, except per share amounts	2005	2004
Net income, as reported	$ 193	$ 153
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	(1)	(1)
Pro-forma net income	$ 192	$ 152

Earnings per share:		
Basic - as reported	$2.50	$2.30
Basic - pro-forma	$2.48	$2.28
Diluted - as reported	$2.48	$2.28
Diluted - pro-forma	$2.47	$2.26

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 become fully exercisable not earlier than six months after the date of grant and 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, 2006, we had $3 million of total unrecognized compensation costs related to stock options. These costs are expected to be recognized over the remaining average requisite service period of approximately two years. Cash received from stock option exercises for the year ended December 31, 2006 was $13 million, and the income tax benefit from stock option exercises was $3 million. The following tables summarize activity related to grants of stock options for key employees and non-employee directors.

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Stock Options

	Number of Options		Weighted Average Exercise Price	Weighted Average Remaining Life (in years)		Aggregate Intrinsic Value (in millions)
Outstanding - December 31, 2003	3,510,970	$	22.25			
Granted	103,900		29.72			
Exercised	(1,050,053)		20.90			
Forfeited	(390,745)		22.44			
Outstanding - December 31, 2004	2,174,072	$	23.23			
Granted	1,014,121		33.80			
Exercised	(846,465)		22.60			
Forfeited	(120,483)		32.38			
Outstanding - December 31, 2005	2,221,245	$	27.79	6.8		
Granted	914,216		35.81	9.1		
Exercised	(543,557)		24.69	4.8		
Forfeited	(266,418)		34.93	8.4		
Outstanding - December 31, 2006	2,325,486	$	30.85	7.2	$	19
Exercisable - December 31, 2006	1,013,672	$	25.45	5.3	$	14

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, 2005	945,556	$	33.64	2.1	$	4.72
Granted	914,216		35.81	2.1		4.79
Forfeited	(266,418)		34.93	1.4		4.95
Vested	(281,540)		32.96	-		4.58
Outstanding - December 31, 2006	1,311,814	$	35.03	1.8	$	4.75

Information about outstanding and exercisable options as of December 31, 2006, 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
$15.80 to $19.74	17,953	2.9	$	17.92	17,953	$	17.92
$19.75 to $23.69	449,825	3.4		21.05	449,825		21.05
$23.70 to $27.64	302,882	6.4		26.55	302,882		26.55
$27.65 to $31.59	52,818	6.2		29.05	47,317		29.03
$31.60 to $35.54	579,239	8.0		33.31	172,660		33.30
$35.55 to $39.49	922,769	9.0		35.86	23,035		36.38
Outstanding - Dec. 31, 2006	**2,325,486**	**7.2**	**$**	**30.85**	**1,013,672**	**$**	**25.45**

Summarized below are outstanding options that are fully exercisable.

Exercisable at:	Number of Options		Weighted Average Exercise Price
December 31, 2004	1,658,260	$	22.04
December 31, 2005	1,275,689	$	23.46
December 31, 2006	1,013,672	$	25.45

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In accordance with the fair value method of determining compensation expense, we used 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 the years ended December 31, 2006, 2005 and 2004.

	2006	2005	2004
Expected life (years)	7	7	7
Risk-free interest rate % (1)	4.5 - 5.1	3.9 - 4.5	3.2 - 4.4
Expected volatility % (2)	14.2 - 15.9	17.1 - 17.3	17.4 - 18.2
Dividend yield % (3)	3.7 - 4.2	3.2 - 3.8	3.5 - 4.1
Fair value of options granted (4)	$4.55 - $6.18	$4.57 - $6.01	$3.62 - $4.07

(1) US Treasury constant maturity - 7 years.
(2) Volatility is measured over 7 years, the expected life of the options. Weighted average for the years ended December 31, 2006, 2005 and 2004 was 15.8%, 17.3% and 17.8%, respectively.
(3) Weighted average dividend yields for the years ended December 31, 2006, 2005 and 2004 were 4.1%, 3.7% and 3.9%, respectively.
(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 the years ended December 31, 2006, 2005 and 2004 was $7 million, $12 million and $10 million, respectively. We use shares purchased under our share repurchase 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 or (ii) cash, subject to the achievement of certain pre-established performance criteria. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment.

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 February 2006, we granted to a select group of officers a total of 64,700 restricted stock units (the 2006 restricted stock units) under the LTIP, of which 61,800 of these units were outstanding as of December 31, 2006. These restricted stock units have a 12-month performance measurement period related to a basic earnings per share goal. The performance measure was achieved during 2006. On January 30, 2007, these restricted stock units were converted to an equal number of shares of our common stock and are now subject to time-based vesting.

Performance Cash Units In general, a performance cash unit is an award that represents the opportunity to receive a cash award, subject to the achievement of certain pre-established performance criteria. We made two grants in January 2005 and 2006 subject to achieving certain performance criteria and the status of those grants is as follows:

In millions	Units	Measurement Period	12 Month paid	24 Month paid	Accrued at December 31, 2006	Maximum Aggregate Payout
2005	23	12-36 months	$ 1	$ -	$ 1	$ 3
2006	15	12-36 months	-	-	1	2

Stock and Restricted Stock Awards

In general, we refer to an award of our common stock that is subject to time-based vesting or achievement of performance measures as "restricted stock." Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment.

Stock Awards Under the 1996 Directors Plan and 2006 Directors Plan (collectively, the Directors Plans), each non-employee director receives an annual retainer that is fixed from time to time by our Board of Directors. Effective as of the date of the 2007 annual shareholder meeting, the annual retainer will increase from $90,000 to $105,000, of which (1) $35,000 (the "Cash Portion") is payable in cash or, at the election of each director, in shares of our common stock or deferred under the 1998 Common Stock Equivalent Plan for Non-Employee Directors (CSE Plan), and (2) $70,000 (the "Equity Portion") is payable, at the election of each director, in shares of our common stock or deferred under the CSE Plan. During the 2006 service term, the annual retainer was $90,000, of which the Cash Portion was $30,000 and the Equity Portion was $60,000. Upon initial election to our Board of Directors, each non-employee director receives 1,000 shares of common stock as of the first day of his or her service. Shares issued under the Directors Plan are 100% vested and nonforfeitable as of the date of grant.

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Restricted Stock Awards Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment. The following table summarizes activity during the year ended December 31, 2006, related to restricted stock awards for our key employees.

Restricted Stock Awards	Shares of Restricted Stock	Weighted Average Remaining Vesting Period (in years)	Weighted Average Fair Value
Outstanding - December 31, 2005	120,728	2.3	$ 34.33
Issued	198,395	2.6	35.68
Forfeited	(30,466)	1.5	34.44
Vested	(56,226)	-	34.21
Outstanding - December 31, 2006	232,431	2.4	$ 35.49

Employee Stock Purchase Plan

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. As of December 31, 2006, our employees had purchased a total of 159,542 shares leaving 440,458 shares available for purchase. The ESPP expires January 31, 2015.

	2006	2005	2004
Shares purchased on the open market	45,361	40,927	35,789
Average per-share purchase price	$ 31.40	$ 30.52	$ 25.20
Purchase price discount	$ 252,752	$ 220,847	$ 159,144

Note 6 - Common Shareholders' Equity

Share Repurchases

In March 2001, our Board of Directors approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the Officer Incentive Plan. In 2006, we purchased 32,801 shares. As of December 31, 2006, we had purchased a total 286,567 shares, leaving 313,433 shares available for purchase. 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 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 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. As of December 31, 2006, we had repurchased 1,027,500 shares at a weighted average price of $36.67.

Dividends

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. 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, 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 and total shareholders' equity covenants
- our ability to satisfy our obligations to any preferred shareholders

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Note 7 - Debt

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions, the SEC and the FERC. On April 1, 2004, we received approval from the SEC, under the Public Utility Holding Act of 1935, as amended (PUHCA), for the renewal of our financing authority to issue securities through April 2007. In August 2005, the Energy Policy Act of 2005 (Energy Act) was enacted which repealed the PUHCA, effective February 8, 2006. The Energy Act granted the FERC financing authorization approvals that were previously required by the SEC under the PUHCA. The following table provides more information on our various securities.

			Outstanding as of:	
In millions	Year(s) due	Int. rate (1)	Dec. 31, 2006	Dec. 31, 2005
Short-term debt				
Commercial paper (2)	2007	5.4%	$ 508	$ 485
Current portion of long-term debt	2007	7.0	11	-
Sequent line of credit (3)	2007	5.6	2	-
Pivotal Utility Holdings, Inc. line of credit (4)	2007	5.7	17	-
Capital leases	2007	4.9	1	1
SouthStar line of credit (5)	-	-	-	36
Total short-term debt (6)		**5.4%**	**$ 539**	**$ 522**
Long-term debt - net of current portion				
Medium-term notes	2012-2027	6.6-9.1%	$ 196	$ 208
Senior notes	2011-2034	4.5-7.1	1,150	975
Gas facility revenue bonds	2022-2033	3.6-5.7	199	199
Notes payable to Trusts	2037	8.2	77	232
Capital leases	2013	4.9	6	6
AGL Capital interest rate swaps	2011	9.0	(6)	(5)
Total long-term debt (6)		**6.2%**	**$ 1,622**	**$ 1,615**
Total debt (6)		**6.0%**	**$ 2,161**	**$ 2,137**

(1) As of December 31, 2006.
(2) The daily weighted average interest rate was 5.1% for 2006 and 3.6% for 2005.
(3) The daily weighted average interest rate was 5.5% for 2006.
(4) The daily weighted average interest rate was 5.7% for 2006.
(5) The daily weighted average interest rate was 6.8% for 2005
(6) Weighted average interest rate, including interest rate swaps if applicable and excluding debt issuance and other financing-related costs.

Short-term Debt

Our short-term debt at December 31, 2006 and 2005 was composed of borrowings under our commercial paper program which consisted of short-term, unsecured promissory notes with maturities ranging from 2 to 38 days; current portions of our capital lease obligations and the current portion of our long-term medium-term notes; and lines of credit for SouthStar, Sequent, and Pivotal Utility Holdings, Inc. (Pivotal Utility).

Commercial Paper In August 2006, we replaced our previous Credit Facility with a new Credit Facility that supports our commercial paper program. Under the terms of the new Credit Facility, the aggregate principal amount available was increased from $850 million to $1 billion and we have the option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year. This credit facility expires August 31, 2011.

SouthStar Credit Facility In November of 2006, SouthStar closed a five-year $75 million unsecured credit facility. This line of credit will be used for working capital and general corporate needs. On December 31, 2006, there were no outstanding borrowings on this line of credit.

Sequent Line of Credit In 2006, we extended Sequent's two lines of credit through June 2007 and August 2007. These unsecured lines of credit, which total $45 million and bear interest at the federal funds effective rate plus 0.4%, are used solely for the posting of margin deposits for NYMEX transactions and are unconditionally guaranteed by us.

Pivotal Utility Line of Credit In August 2006, we extended the Pivotal Utility line of credit through August 2007. This line of credit supports Elizabethtown Gas' hedging program and bears interest at the federal funds effective rate plus 0.4%, is used solely for the posting of deposits and is unconditionally guaranteed by us. For more information on Elizabethtown Gas' hedging program, see Note 2.

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Long-term Debt

Our long-term debt matures more than one year from the date of issuance 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; notes payable to Trusts; and capital leases. The notes are unsecured and rank on parity with all our other unsecured indebtedness. Our annual maturities of long-term debt are as follows:

Year	Amount (in millions)
2011	$ 294(1)
2012	15
2013	230
2015	200
2016	175
2017	22
2021	30
2022	93
2024	20
2026	69
2027	54
2032	55
2033	40
2034	250
2037	77
Total	$ 1,624(2)

(1) Includes the fair value of $6 million related to our interest rate swaps.

(2) Excludes $2 million of unamortized issuance costs related to our gas facility revenue bonds.

Medium-term notes The following table provides more information on our medium-term notes, which were issued to refinance portions of our existing short-term debt and for general corporate purposes. Our annual maturities of our medium-term notes are as follows:

Issue Date	Amount (in millions)	Interest Rate	Maturity
Feb. 1991	$ 30	9.1%	Feb. 2021
June 1992	5	8.4	June 2012
June 1992	5	8.3	June 2012
June 1992	5	8.3	July 2012
April 1992	5	8.55	April 2022
	25	8.7	

April 1992			April 2022
April 1992	6	8.55	April 2022
May 1992	10	8.55	May 2022
July 1997	22	7.2	July 2017
Nov. 1996	30	6.55	Nov. 2026
July 1997	53	7.3%	July 2027
Total	$ 196		

In December 2006, we executed our option to redeem an $11 million medium-term note in January of 2007. The note had an interest rate of 7% and was previously scheduled to mature in January of 2015. The note was redeemed at par using proceeds from commercial paper.

Senior Notes The following table provides more information on our senior notes, which were issued to refinance portions of our existing short-term debt and medium-term notes, to finance acquisitions and for general corporate purposes. Our annual maturities of our senior notes are as follows:

Issue Date	Amount (in millions)	Interest Rate	Maturity
Feb. 2001	$ 300	7.125%	Jan 2011
July 2003	225	4.45	Apr 2013
Sep. 2004	250	6.0	Oct 2034
Dec. 2004	200	4.95	Jan 2015
June 2006	175	6.375%	Jul 2016
Total	$ 1,150		

In June 2006, we issued $175 million of 10-year senior notes at an interest rate of 6.375% and used the net proceeds of $173 million to repay the commercial paper. In March 2003, we entered into interest rate swaps of $100 million to effectively convert a portion of the fixed-rate interest obligation on the $300 million in Senior Notes due 2011 to a variable-rate obligation. We pay floating interest each January 14 and July 14 at six-month LIBOR plus 3.4%. The effective variable interest rate at December 31, 2006, was 9.0%. These interest rate swaps expire January 14, 2011, unless terminated earlier. For more information on our interest rate swaps, see Note 2.

The trustee with respect to all of the above-referenced senior notes is The Bank of New York Trust Company, N.A. (Bank of New York), pursuant to an indenture dated February 20, 2001. We fully and unconditionally guarantee all of our senior notes.

Gas Facility Revenue Bonds Pivotal Utility has $200 million of indebtedness pursuant to gas facility revenue bonds. We do not guarantee or provide any other form of security for the repayment of this indebtedness. 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 as follows:

Issue Date	Amount (in millions)	Interest Rate	Maturity
July 1994	$ 47	(1)	Oct. 2022
July 1994	20	(1)	Oct. 2024
June 1992	39	(1)	June 2026
June 1992	55	5.7%	June 2032
July 1997	40	5.25%	Nov. 2033
Unamortized issuance costs	(2)		
Total	$ 199		

(1) Variable or adjusting rates.

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In April 2005, we refinanced $20 million of our Gas Facility Revenue Bonds due October 1, 2024. The original bonds had a fixed interest rate of 6.4% per year and were refunded with $20 million of adjustable-rate gas facility revenue bonds. The maturity date of these bonds remains October 1, 2024. The new bonds were issued at an initial annual interest rate of 2.8% and initially have a 35-day auction period where the interest rate will adjust every 35 days. The interest rate at December 31, 2006 was 3.7%.

In May 2005, we refinanced an additional $47 million in Gas Facility Revenue Bonds due October 1, 2022 and bearing interest at an annual fixed rate of 6.35%. The new bonds were issued at an initial annual interest rate of 2.9% and initially have a 35-day auction period where the interest rate will adjust every 35 days. The maturity date remains October 1, 2022. The interest rate at December 31, 2006 was 3.6%.

The variable bonds contain a provision whereby the holder can "put" the bonds back to the issuer. In 1996, Pivotal Utility executed a long-term Standby Bond Purchase Agreement (SBPA) with a syndicate of banks, which was amended and restated on June 1, 2005. Under the terms of the SBPA, as further amended, the participating banks are obligated under certain circumstances to purchase variable bonds that are tendered by the holders thereof and not remarketed by the remarketing agent. Such obligation of the participating banks would remain in effect until the June 1, 2010 expiration of the SBPA, unless it is extended or earlier terminated.

Notes Payable to Trusts In June 1997, we established AGL Capital Trust I (Trust I), a Delaware business trust, of which AGL Resources owns all the common voting securities. Trust I issued and sold $75 million of 8.17% capital securities (liquidation amount $1,000 per capital security) to certain initial investors. Trust I used the proceeds to purchase 8.17% junior subordinated deferrable interest debentures issued by us. Trust I capital securities are subject to mandatory redemption at the time of the repayment of the junior subordinated debentures on June 1, 2037, or the optional prepayment by us after May 31, 2007.

In May 2001, AGL Capital Trust II (Trust II) issued and sold $150 million of 8.00% capital securities and used the proceeds to purchase $150 million principal amount of 8.00% junior subordinated deferrable interest debentures from us. In May 2006, we used the proceeds from the sale of commercial paper to redeem the $150 million of junior subordinated debentures and to pay a $5 million note representing our investment in the Trust, previously included in notes payable to trusts.

The trustee is the Bank of New York with respect to the 8.17% capital securities pursuant to an indenture dated June 11, 1997. We fully and unconditionally guarantee all our Trust I obligations for the capital securities.

Other Preferred Securities As of December 31, 2006, 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 over 11 years. 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.

Default Events

Our Credit Facility financial covenant requires us to maintain a ratio of total debt to total capitalization of no greater than 70%. As of December 31, 2006 this ratio was 57%. 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 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 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 8 - Commitments and Contingencies

Contractual Obligations and Commitments

We have incurred various contractual obligations and financial commitments in the normal course of our operating and financing activities. 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. We calculate any expected pension contributions using the projected unit credit cost method. Under this method, we were not required to make any pension contribution in 2006, but we voluntarily made a $5 million contribution in October 2006. The following table illustrates our expected future contractual cash obligations as of December 31, 2006.

		Payments due before December 31,			
In millions	**Total**	**2007**	**2008 & 2009**	**2010 & 2011**	**2012 & thereafter**
Interest charges (1)	$ 1,398	$ 99	$ 198	$ 177	$ 924
Pipeline charges, storage capacity and gas supply (2) (3) (4)	1,916	441	625	389	461
Long-term debt (5)	1,622	-	-	300	1,322
Short-term debt	539	539	-	-	-
PRP costs (6)	237	35	82	85	35
Operating leases (7)	170	32	47	34	57
ERC (6)	96	13	18	54	11
Total	$ 5,978	$ 1,159	$ 970	$ 1,039	$ 2,810

(1) Floating rate debt is based on the interest rate as of December 31, 2006 and the maturity of the underlying debt instrument.
(2) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.
(3) A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS No. 141, “Business Combinations,“ we valued the contracts at fair value and established a long-term liability that will be amortized over the remaining lives of the contracts.
(4) Amount includes SouthStar gas commodity purchase commitments of 1.4 Bcf at floating gas prices calculated using a forward natural gas price as of December 31, 2006, and is valued at $89 million.
(5) Includes $77 million of notes payable to Trusts redeemable in 2007.
(6) Includes charges recoverable through rate rider mechanisms.
(7) 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 SFAS No. 13, “Accounting for Leases.” However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

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. The following table illustrates our expected contingent financial commitments as of December 31, 2006.

In millions	Total	2007	Commitments due before Dec. 31, 2008 & thereafter
Standby letters of credit, performance / surety bonds	$ 14	$ 12	$ 2

Rental Expense

We incurred $19 million, $25 million and $22 million in rental expense in 2006, 2005 and 2004, respectively.

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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 August 2006, the Office of Mineral Resources of the Louisiana Department of Natural Resources (Louisiana DNR) informed Jefferson Island that its mineral lease - which authorizes salt extraction to create two new storage caverns - at Lake Peigneur had been terminated. The Louisiana DNR identified two bases for the termination: (1) failure to make certain mining leasehold payments in a timely manner, and (2) the absence of salt mining operations for six months.

In September 2006, Jefferson Island filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Jefferson Island. In its suit, Jefferson Island alleges that the Louisiana DNR accepted all leasehold payments without reservation and never provided Jefferson Island with notice and opportunity to cure, as required by state law. In its answer to the suit, the State denied that anyone with proper authority approved the late payments. As to the second basis for termination, the suit contends that Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. The State's answer denies that the 2004 amendment was properly authorized. We continue to seek resolution of this dispute and we are optimistic that a settlement can be reached with the State of Louisiana that would allow us to proceed with the expansion. If we are unable to reach a settlement, we are not able to predict the outcome of the litigation. As of January 2007, our current estimate of costs incurred that would be considered unusable if the Louisiana DNR was successful in terminating our lease and causing us to cease the expansion project is approximately $8 million.

Environmental Remediation Costs

We own a former NUI remediation site in Elizabeth City, North Carolina that is subject to a remediation order by the North Carolina Department of Energy and Natural Resources. As of December 31, 2006, we have recorded a liability of $10 million related to this site.

There is one other site in North Carolina where investigation and remediation is likely, although no remediation order exists and we do not believe costs associated with this site can be reasonably estimated. In addition, there are as many as six other sites with which NUI had some association, although no basis for liability has been asserted, and accordingly we have not accrued any remediation liability. There are currently no cost recovery mechanisms for the environmental remediation sites in North Carolina.

Note 9 - Fair Value of Financial Instruments

The following table shows the carrying amounts and fair values of our long-term debt including any current portions included in our consolidated balance sheets.

In millions	Carrying Amount (1)	Estimated Fair Value
As of December 31, 2006	$ 1,633	$ 1,716
	1,615	1,784

As of
December
31, 2005

(1) Includes $11 million of medium-term notes reported as short-term debt in our December 31, 2006, consolidated balance sheets.

The estimated fair values are determined based on interest rates that are currently available for issuance of debt with similar terms and remaining maturities.

Considerable judgment is required to develop the fair value estimates; therefore, the values are not necessarily indicative of the amounts that could be realized in a current market exchange. The fair value estimates are based on information available to management as of December 31, 2006. We are not aware of any subsequent factors that would significantly affect the estimated fair value amounts. For more information about the fair values of our interest rate swaps, see Note 2.

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Note 10 - Income Taxes

We have two categories of income taxes in our statements of consolidated 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 Tax Credits

Deferred investment tax credits associated with distribution operations are included as a regulatory liability in our consolidated balance sheets (see Note 3, Regulatory Assets and Liabilities). These investment tax credits are being amortized over the estimated life of the related properties as credits to income in accordance with regulatory requirements. We reduce income tax expense in our statements of consolidated income for the investment tax credits and other tax credits associated with our nonregulated subsidiaries. Components of income tax expense shown in the statements of consolidated income are as follows.

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. Additionally, 2006 was significantly impacted by our mark-to-market gains on energy risk management assets which are not recognized for tax purposes until realized.

In millions	2006	2005	2004
Current income taxes			
Federal	$ (4)	$ 84	$ 25
State	2	18	1
Deferred income taxes			
Federal	115	17	60
State	18	-	5
Amortization of investment tax credits	(2)	(2)	(1)
Total	$ 129	$ 117	$ 90

The reconciliations between the statutory federal income tax rate, the effective rate and the related amount of tax for the years ended December 31, 2006, 2005 and 2004 are presented in the following tables.

2006

In millions	Amount	% of pretax income
Computed tax expense at statutory rate	$ 119	35.0%
State income tax, net of federal income tax benefit	12	3.6
	(2)	(0.5)

Amortization of investment tax credits			
Flexible dividend deduction		(2)	(0.5)
Other -- net		2	0.2
Total income tax expense at effective rate	$	129	37.8%

2005

In millions		Amount	% of pretax income
Computed tax expense at statutory rate	$	109	35.0%
State income tax, net of federal income tax benefit		11	3.7
Amortization of investment tax credits		(2)	(0.6)
Flexible dividend deduction		(2)	(0.6)
Other - net		1	0.2
Total income tax expense at effective rate	$	117	37.7%

2004

In millions		Amount	% of pretax income
Computed tax expense at statutory rate	$	85	35.0%
State income tax, net of federal income tax benefit		9	3.5
Amortization of investment tax credits		(1)	(0.6)
Flexible dividend deduction		(2)	(0.6)
Other - net		(1)	(0.2)
Total income tax expense at effective rate	$	90	37.1%

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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 balance sheets. 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 SFAS 109, which we are amortizing over approximately 30 years (see Note 3). Our deferred tax assets include $35 million related to an additional minimum pension liability, a decrease of $2 million from 2005.

As indicated in the following table, our deferred tax assets and liabilities include certain items we acquired from NUI. 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	
In millions	Dec. 31, 2006	Dec. 31, 2005
Accumulated deferred income tax liabilities		
Property -- accelerated depreciation and other property-related items	$ 520	$ 494
Mark to market	46	1
Other	22	38
Total accumulated deferred income tax liabilities	588	533
Accumulated deferred income tax assets		
Deferred investment tax credits	7	7
Deferred pension additional minimum liability	35	37
Net operating loss - NUI (1)	5	26
Capital loss carryforward	-	4
Alternative minimum tax credit	-	8
Other	-	37
Total accumulated deferred income tax assets	47	119
Valuation allowances (2)	(3)	(9)
Total accumulated deferred income tax assets, net of valuation allowance	44	110
Net accumulated deferred tax liability	$ 544	$ 423

(1) Expire in 2021.

(2) Valuation allowance is due to the net operating losses on NUI headquarters that are not usable in New Jersey.

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Note 11 - Segment Information

Our four operating segments are as follows:

- Distribution operations consists primarily of
  - Atlanta Gas Light
  - Chattanooga Gas
  - Elizabethtown Gas
  - Elkton Gas
  - Florida City Gas
  - Virginia Natural Gas
- Retail energy operations consists of SouthStar
- Wholesale services consists of Sequent
- Energy investments consists primarily of
  - AGL Networks, LLC
  - Jefferson Island
  - Pivotal Propane

We treat corporate, our fifth segment, as a nonoperating business segment, and it currently includes AGL Resources, AGL Services Company, Pivotal Energy Development and the effect of intercompany eliminations. We eliminated intercompany sales for the years ended December 31, 2006, 2005 and 2004 from our statements of consolidated income.

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, other income, donations, minority interest in 2006, 2005 and 2004 and gains on sales of assets. 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 and net income for the years ended December 31, 2006, 2005 and 2004 are presented below.

In millions	2006	2005	2004
Operating revenues	$ 2,621	$ 2,718	$ 1,832
Operating expenses	2,133	2,276	1,500
Operating income	488	442	332
Other expenses	(1)	(1)	-
Minority interest	(23)	(22)	(18)
EBIT	464	419	314
Interest expense	123	109	71
Earnings before income taxes	341	310	243
Income taxes	129	117	90
Net income	$ 212	$ 193	$ 153

Summarized income statement, balance sheet and capital expenditure information by segment as of and for the years ended December 31, 2006, 2005 and 2004 is shown in the following tables.

2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$ 1,467	$ 930	$ 182	$ 41	$ 1	$ 2,621
Intercompany revenues (1)	157	-	-	-	(157)	-
Total revenues	1,624	930	182	41	(156)	2,621
Operating expenses						
Cost of gas	817	774	43	5	(157)	1,482
Operation and maintenance	350	64	46	20	(7)	473
Depreciation and amortization	116	3	2	5	12	138
Taxes other than income taxes	33	1	1	1	4	40
Total operating expenses	1,316	842	92	31	(148)	2,133
Operating income (loss)	308	88	90	10	(8)	488
Minority interest	-	(23)	-	-	-	(23)
Other income (expense)	2	(2)	-	-	(1)	(1)
EBIT	$ 310	$ 63	$ 90	$ 10	$ (9)	$ 464
Identifiable and total assets	$ 4,565	$ 298	$ 849	$ 373	$ 62	$ 6,147
Goodwill	$ 406	$ -	$ -	$ 14	$ -	$ 420
Capital expenditures	$ 174	$ 9	$ 2	$ 23	$ 45	$ 253

2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$ 1,571	$ 996	$ 95	$ 56	$ -	$ 2,718
Intercompany revenues (1)	182	-	-	-	(182)	-
Total revenues	1,753	996	95	56	(182)	2,718
Operating expenses						
Cost of gas	939	850	3	16	(182)	1,626
Operation and maintenance	372	58	39	17	(9)	477
Depreciation and amortization	114	2	2	5	10	133
Taxes other than income taxes	32	1	1	1	5	40
Total operating expenses	1,457	911	45	39	(176)	2,276
Operating income (loss)	296	85	50	17	(6)	442
Minority interest	-	(22)	-	-	-	(22)
Other income (expense)	3	-	(1)	2	(5)	(1)

EBIT	$	299	$	63	$	49	$	19	$	(11)	$	419
Identifiable and total assets	$	4,788	$	343	$	1,058	$	350	$	(219)	$	6,320
Goodwill	$	406	$	-	$	-	$	14	$	-	$	420
Capital expenditures	$	215	$	4	$	1	$	9	$	38	$	267

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2004

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues	$ 926	$ 827	$ 54	$ 25	$ -	$ 1,832
Intercompany revenues (1)	185	-	-	-	(185)	-
Total revenues	1,111	827	54	25	(185)	1,832
Operating expenses						
Cost of gas	471	695	1	12	(184)	995
Operation and maintenance	286	60	27	5	(1)	377
Depreciation and amortization	85	2	1	2	9	99
Taxes other than income taxes	23	-	1	1	4	29
Total operating expenses	865	757	30	20	(172)	1,500
Operating income (loss)	246	70	24	5	(13)	332
Earnings in equity interests	-	-	-	2	-	2
Minority Interest	-	(18)	-	-	-	(18)
Other income (expense)	1	-	-	-	(3)	(2)
EBIT	$ 247	$ 52	$ 24	$ 7	$ (16)	$ 314
Identifiable assets	$ 4,383	$ 244	$ 696	$ 386	$ (86)	$ 5,623
Investment in joint ventures	-	-	-	235	(221)	14
Total assets	$ 4,383	$ 244	$ 696	$ 621	$ (307)	$ 5,637
Goodwill	$ 340	$ -	$ -	$ 14	$ -	$ 354
Capital expenditures	$ 205	$ 4	$ 8	$ 36	$ 11	$ 264

(1) Intercompany revenues - Wholesale services records its energy marketing and risk management revenue on a net basis. Wholesale services total operating revenues include intercompany revenues of $531 million, $792 million and $369 million for the years ended December 31, 2006, 2005 and 2004, respectively.

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Note 12 - Quarterly Financial Data (Unaudited)

Our quarterly financial data for 2006, 2005 and 2004 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
2006				
Operating revenues	$ 1,044	$ 436	$ 434	$