AGL RESOURCES INC
Form 10-K/A
June 01, 2006

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

**FORM 10-K/A**
**Amendment No. 1**

(Mark One)

**[ü] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

**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**<br>(State or other jurisdiction of incorporation or organization) | **58-2210952**<br>(I.R.S. Employer Identification No.) |
| **Ten Peachtree Place NE,**<br>**Atlanta, Georgia 30309**<br>(Address and zip code of principal executive offices) | **404-584-4000**<br>(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** |
| **Preferred Share Purchase Rights** | **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 [ü] 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 [ü ]

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 [ü] 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. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 under the Exchange Act. Large accelerated filer [ ü] 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 [ü]

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 $2,989,393,874

The number of shares of the registrant's common stock outstanding as of January 31, 2006 was 77,849,574.

**DOCUMENTS INCORPORATED BY REFERENCE:**

Portions of the Proxy Statement for the 2006 Annual Meeting of Shareholders ("Proxy Statement") held May 3, 2006, are incorporated by reference in Part III.

**Explanatory Note**

We are filing this Amendment No. 1 to our Annual Report on Form 10-K for the year ended December 31, 2005, for the purpose of amending Item 9A to clarify that there have been no changes in our internal control over financial reporting that occurred during our fourth quarter ended December 31, 2005 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We are also correcting the format of the certifications filed previously as Exhibits 31.1 and 31.2 with the original Form 10-K. In addition, in connection with the filing of this amendment, we are including updated consent letters from our independent registered public accounting firm and from SouthStar Energy Services LLC’s independent registered public accounting firm as exhibits, and we are furnishing certain other currently dated certifications of our chief executive officer and chief financial officer as exhibits.

The remainder of the information contained in the original Form 10-K is reproduced in this amendment, but this amendment does not reflect events occurring after the filing of the original Form 10-K or, except as indicated above, modify or update the information in the original Form 10-K.

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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 |
| Chattanooga Gas | Chattanooga Gas Company |
| Credit Facility | Credit agreement supporting our commercial paper program |
| 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 |
| ERC | Environmental remediation costs |
| FASB | Financial Accounting Standards Board |
| Florida Commission | Florida Public Service Commission |
| GAAP | Accounting principles generally accepted in the United States of America |
| Georgia Commission | Georgia Public Service Commission |
| Henry Hub | The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. 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. |
| LNG | Liquefied natural gas |
| Marketers | Marketers selling retail natural gas in Georgia and certificated by the Georgia Public Service 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% |
| NJBPU | New Jersey Board of Public Utilities |
| NYMEX | New York Mercantile Exchange, Inc. |
| OCI | Other comprehensive income |
| Operating margin | A 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 on the sale of our Caroline Street campus; 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 |
| Pivotal Jefferson Island | Pivotal Jefferson Island Storage & Hub, LLC |
| Pivotal Propane | Pivotal Propane of Virginia, Inc. |
| Pivotal Utility | Pivotal Utility Holding, Inc., parent company of Elizabethtown Gas, Elkton Gas and Florida City Gas |
| PGA | Purchased gas adjustment |
| PRP | Pipeline replacement program |
| PUHCA | Public Utility Holding Company Act of 1935, as amended |
| Sequent | Sequent Energy Management, L.P. |
| SFAS | Statement of Financial Accounting Standards |
| SouthStar | SouthStar Energy Services LLC |
| Virginia Natural Gas | Virginia Natural Gas, Inc. |
| Virginia Commission | Virginia State Corporation Commission |

**REFERENCED ACCOUNTING STANDARDS**

| | |
|---|---|
| APB 20 | Accounting Principles Board (APB) Opinion No. 20, "Accounting Changes" |
| 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’” |
| 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” |
| 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 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 149 | SFAS No. 149, “Amendment of Statement 133 on Derivative Instruments and Hedging Activities” |
| SFAS 154 | SFAS No. 154, “Accounting Changes and Error Corrections” |

**PART I**

**ITEM 1. BUSINESS**

**Nature of Our Business**

Unless the context requires otherwise, references to "we," "us," "our" or the "company" are intended to mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources). For information on the nature of our business, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," Item 7A, "Quantitative and Qualitative Disclosures About Market Risk" under the caption "Credit Risk" and the notes to our consolidated financial statements set forth in Item 8, "Financial Statements and Supplementary Data."

**Employees**

On December 31, 2005, we had 2,385 employees, and we believe that our employee relations are good.

On April 7, 2005, approximately 53 of 77 Florida City Gas employees covered under collective bargaining agreements with Teamster's Local Nos. 769 and 385 began a work stoppage. The strike lasted for 39 days, ending on May 16, 2005, when a new three-year agreement was reached. The following table provides information on our collective bargaining agreements and the dates they expire:

| | Affiliated subsidiary | Approximate # of employees | Date of contract expiration |
|---|---|---|---|
| Teamsters (Local No. 528) | Atlanta Gas Light | 302 | March 2006 |
| Communications Workers of America (Local No. 1023) | Elizabethtown Gas | 10 | April 2006 |
| International Brotherhood of Electrical Workers (Local No. 50) | Virginia Natural Gas | 146 | May 2006 |
| Utility Workers Union of America (Local No. 461) | Chattanooga Gas | 20 | April 2007 |
| International Union of Operating Engineers (Local No. 474) | Atlanta Gas Light | 24 | August 2007 |
| Teamsters (Local Nos. 769 and 385) | Florida City Gas | 53 | March 2008 |
| Utility Workers Union of America (Local No. 424) | Elizabethtown Gas | 166 | November 2009 |
| Total | | 721 | |

**Available Information**

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, that we file with or furnish to the Securities and Exchange Commission (SEC) 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. The posting of these reports on our website does not incorporate by reference the other information contained on the website, and such other information on our website should not be considered part of such reports unless we expressly incorporate such other information by reference. We will furnish copies of such reports free of charge upon written request to our Investor Relations department.

Additionally, our corporate governance guidelines, code of ethics, code of business conduct and the charters of each of our Board committees are available on our website. We will furnish copies of such information 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
Ten Peachtree Place, NE
Atlanta, GA 30309
404-584-3801

**ITEM 1A. RISK FACTORS**

Risk Factors related to our business, our corporate and financial structure, our industry and the investment in our common stock are set forth in Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" under the caption "Risk Factors."

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

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

**ITEM 2. PROPERTIES**

In 2005, we added an additional segment, retail energy operations. Information on the addition of this segment is contained in Note 14 to our consolidated financial statements set forth in Item 8, "Financial Statements and Supplementary Data." The principal properties of our four operating segments are described below:

**Distribution Operations** As of December 31, 2005, the properties of our distribution operations segment represented approximately 91% 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 45,000 miles of distribution pipeline. 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 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. 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 10 million Dekatherms (MMDth) of total capacity and about 7.2 MMDth of working gas capacity. The facility has approximately 720,000 Dth/day withdrawal capacity and 360,000 Dth/day injection capacity. We completed a project during the year to expand compression capability, enabling us to increase the number of times a customer can inject and withdraw gas on an annual basis from 10 to 12 times.

We also own a propane facility in Virginia. The propane facility provides our utility in Virginia with 28,800 Dth of propane air per day on a 10 day per year basis.

In addition, energy investments’ properties include telecommunications conduit and fiber existing in public rights of way that is leased to our customers in Atlanta and Phoenix. This includes approximately 72,000 fiber miles, of which approximately 17% of our dark fiber in Atlanta and 22% 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 250,000 square feet of office space. In addition, our retail energy operations leases approximately 26,600 square feet in a different 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.

## 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 10 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, 2005.

**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 |
|---|---|
| **D. Raymond Riddle**, Age 72 | |
| Interim Chairman and Chief Executive Officer | January 2006 - Present |
| Director | May 1978 - Present |
| Chairman | August 2000 - February 2002 |
| | |
| **Kevin P. Madden,** Age 53 (1) | |
| 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,** Age 37 | |
| 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 |
| Executive Vice President and General Manager of AGL Networks, LLC | June 2002 - December 2002 |
| Vice President, Business Development | October 2000 - June 2002 |
| | |
| **Andrew W. Evans,** Age 39 (2) | |
| Senior Vice President and Chief Financial Officer | September 2005 - Present |
| Vice President and Treasurer | April 2002 - September 2005 |
| | |
| **Melanie M. Platt,** Age 51 | |
| Senior Vice President, Human Resources | September 2004 - Present |
| Senior Vice President and Chief Administrative Officer | October 2000 - September 2004 |
| Vice President of Investor Relations | May 1998 - November 2002 |
| Vice President and Corporate Secretary | January 1995 - June 2002 |
| | |
| **Paul R. Shlanta,** Age 48 | |
| 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 |

**Bryan E. Seas,** Age 45 (3)

| | |
|---|---|
| Vice President, Controller and Chief Accounting Officer | September 2005 - Present |
| Vice President and Controller | July 2003 - September 2005 |

(1) Mr. Madden served as general counsel and chief legal advisor to the Federal Energy Regulatory Commission from January 2001 to September 2001.

(2) From March 1995 until joining the Company, Mr. Evans was employed by Mirant Corporation (NYSE: MIR) (formerly Southern Energy, Inc.) where he served from June 2001 until April 2002 as a vice president of corporate development for the company's Mirant Americas business unit. He previously served as vice president and treasurer for Mirant Americas from June 2000 until June 2001; director of finance for Mirant Americas Energy Marketing from March 1999 until June 2000; and project finance associate for Southern Electric International (Mirant's predecessor) from March 1995 until March 1997. Prior to Mirant, Mr. Evans was employed by the Cambridge, MA office of National Economic Research Associates and by the Federal Reserve Bank of Boston.

(3) Mr. Seas spent almost 10 years with El Paso Corporation (NYSE: EP) and one of its predecessor companies, Sonat Inc. Mr. Seas was vice president and controller of El Paso's Global Power Group from September 2002 until June 2003, responsible for accounting, financial reporting, financial systems, budgeting and forecasting. As El Paso's director of corporate accounting from November 2000 until August 2002, Mr. Seas directed the general accounting and financial systems services of the company. Prior to that, Mr. Seas served as director of accounting for El Paso's Southern Natural Gas Company subsidiary from October 1999 until October 2000. Mr. Seas began his career in public accounting with Ernst & Young, LLP in 1987.

**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, 2006, there were approximately 10,979 record holders of our common stock. Quarterly information concerning our high and low stock prices and cash dividends paid in 2005 and 2004 is as follows:

| Quarter ended: | Sales price of common stock High | Sales price of common stock Low | Cash Dividend Per Common Share |
|---|---|---|---|
| **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 |
| **2004** | | | |
| March 31, 2004 | $ 30.63 | $ 27.87 | $ 0.28 |
| June 30, 2004 | 29.41 | 26.50 | 0.29 |
| September 30, 2004 | 31.27 | 28.60 | 0.29 |
| December 31, 2004 | 33.65 | 30.11 | 0.29 |

We pay dividends four times a year: March 1, June 1, September 1 and December 1. We have paid 233 consecutive quarterly dividends beginning in 1948. In February 2005, we increased the quarterly dividend to $0.31 per common share, and in November 2005, we increased the quarterly dividend to $0.37 per common share.

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
- restrictions under the Public Utility Holding Company Act of 1935, as amended (PUHCA), on our payment of dividends out of capital or unearned surplus without prior permission from the SEC. The PUHCA was repealed effective February 8, 2006. For more information about the repeal and its effect on us, see Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations"

Additionally, 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 and junior 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

**Sales of Unregistered Securities**

All of our sales of securities in 2005 were registered under the Securities Act of 1933, as amended.

**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, 2005. All shares were purchased in open market transactions in connection with awards payable in common stock under the AGL Resources Inc. Officer Incentive Plan (OIP). In February 2006, our Board of Directors authorized a plan to repurchase up to 8 million shares of our outstanding common stock over a five-year period. These purchases are intended to principally offset share issuances under our employee incentive compensation plans, director plans, and dividend reinvestment and stock purchase plans. Stock repurchases under this program 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) | | **Average price paid per share** | **Total number of shares purchased as part of publicly announced plans or programs** (2) | **Maximum number of shares that may yet be purchased under the plans or programs** |
|---|---|---|---|---|---|
| October 2005 | 220 | $ | 36.01 | N/A | N/A |
| November 2005 | 108 | $ | 33.96 | N/A | N/A |
| December 2005 | 4,892 | $ | 35.39 | N/A | N/A |
| **Total fourth quarter** | **5,220** | **$** | **35.12** | | |

(1) The total number of shares purchased reflects an aggregate of 5,220 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 June 30, 2004, we announced that our Board of Directors had approved the purchase of up to 600,000 shares of our common stock to be used for issuances under the OIP. As of December 31, 2005, we had purchased 253,766 shares, leaving 346,234 shares available for purchase for use in the OIP. We adopted the OIP on March 20, 2001, and it will expire on March 20, 2011.

The information required by this item regarding securities authorized for issuance under our equity compensation plans is contained under the caption “Executive Compensation - Equity Compensation Plan Information” in the definitive Proxy Statement for our 2006 Annual Meeting of Shareholders filed on March 20, 2006, and such information is incorporated herein by reference. 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.

**ITEM 6. SELECTED FINANCIAL DATA**

Selected financial data about us is set forth in the table below. We derived the data in the table from our audited financial statements. 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." On September 30, 2001, our Board of Directors elected to change our fiscal year end from September 30 to December 31, effective October 1, 2001. We refer to the three months ended December 31, 2001 as the "Transition Period" in the table below.

| *Dollars and shares in millions, except per share amounts* | 2005 | 2004 | 2003 | 2002 | Transition period | 2001 |
|---|---|---|---|---|---|---|
| **Income statement data** | | | | | | |
| Operating revenues | $ 2,718 | $ 1,832 | $ 983 | $ 877 | $ 204 | $ 946 |
| Cost of gas | 1,626 | 995 | 339 | 268 | 49 | 327 |
| Operating margin | 1,092 | 837 | 644 | 609 | 155 | 619 |
| Operating expenses | | | | | | |
| Operation and maintenance | 477 | 377 | 283 | 274 | 68 | 267 |
| Depreciation and amortization | 133 | 99 | 91 | 89 | 23 | 100 |
| Taxes other than income taxes | 40 | 29 | 28 | 29 | 6 | 33 |
| Total operating expenses | 650 | 505 | 402 | 392 | 97 | 400 |
| Gain on sale of Caroline Street campus | - | - | 16 | - | - | - |
| Operating income | 442 | 332 | 258 | 217 | 58 | 219 |
| Equity in earnings of SouthStar Energy Services LLC | - | - | 46 | 27 | 4 | 14 |
| Other (loss) income | (1) | - | (6) | 3 | 1 | 4 |
| Minority interest | (22) | (18) | - | - | - | - |
| Interest expense | (109) | (71) | (75) | (86) | (24) | (98) |
| Earnings before income taxes | 310 | 243 | 223 | 161 | 39 | 139 |
| Income taxes | 117 | 90 | 87 | 58 | 14 | 50 |
| Income before cumulative effect of change in accounting principle | 193 | 153 | 136 | 103 | 25 | 89 |
| Cumulative effect of change in accounting principle, net of $5 in income taxes | - | - | (8) | - | - | - |
| Net income | $ 193 | $ 153 | $ 128 | $ 103 | $ 25 | $ 89 |
| **Common stock data** | | | | | | |
| Weighted average shares outstanding-basic | 77.3 | 66.3 | 63.1 | 56.1 | 55.3 | 54.5 |
| Weighted average shares outstanding-fully diluted | 77.8 | 67.0 | 63.7 | 56.6 | 55.6 | 54.9 |
| Total shares outstanding (1) | 77.8 | 76.7 | 64.5 | 56.7 | 55.6 | 55.1 |
| Earnings per share-basic | $ 2.50 | $ 2.30 | $ 2.03 | $ 1.84 | $ 0.45 | $ 1.63 |
| Earnings per share-fully diluted | $ 2.48 | $ 2.28 | $ 2.01 | $ 1.82 | $ 0.45 | $ 1.62 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Dividends per share | $ 1.30 | $ 1.15 | $ 1.11 | $ 1.08 | $ 0.27 | $ 1.08 |
| Dividend payout ratio | 52% | 50% | 55% | 59% | 60% | 66% |
| Book value per share (2) | $ 19.27 | $ 18.04 | $ 14.66 | $ 12.52 | $ 12.41 | $ 12.20 |
| Market value per share (3) | $ 34.81 | $ 33.24 | $ 29.10 | $ 24.30 | $ 23.02 | $ 19.97 |
| **Balance sheet data** (1) | | | | | | |
| Total assets | $ 6,251 | $ 5,637 | $ 3,972 | $ 3,742 | $ 3,454 | $ 3,368 |
| Long-term liabilities | 737 | 682 | 647 | 702 | 671 | 711 |
| Minority interest | 38 | 36 | - | - | - | - |
| Capitalization | | | | | | |
| Long-term debt (excluding current portion) | 1,615 | 1,623 | 956 | 994 | 1,015 | 1,065 |
| Common shareholders' equity | 1,499 | 1,385 | 945 | 710 | 690 | 671 |
| Total capitalization | $ 3,114 | $ 3,008 | $ 1,901 | $ 1,704 | $ 1,705 | $ 1,736 |
| **Financial ratios** (1) | | | | | | |
| Capitalization | | | | | | |
| Long-term debt | 52% | 54% | 50% | 58% | 60% | 61% |
| Common shareholders' equity | 48 | 46 | 50 | 42 | 40 | 39 |
| Total | 100% | 100% | 100% | 100% | 100% | 100% |
| Return on average common shareholders' equity | 13.4% | 13.1% | 15.5% | 14.7% | 14.6% | 13.8% |

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

(2) Common shareholders' equity divided by total outstanding common shares as of the last day of the fiscal period.

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

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

## CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain expectations and projections regarding our future performance referenced in this Management’s Discussion and Analysis of Financial Condition and Results of Operations section and elsewhere in this report, as well as in other reports and proxy statements we file with the Securities and Exchange Commission (SEC), are forward-looking statements. Officers and other employees may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements involve matters that are not historical facts, and because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate," "assume," "can," "could," "estimate," "expect," "forecast," "future," "indicate," "intend," "may," “outlook,” "plan," "predict," "project,” "seek," "should," "target," "will," "would," or similar expressions. Our expectations are not guarantees and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of the currently available information, our expectations are subject to future events, risks and uncertainties, and there are several 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, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact of acquisitions and divestitures; direct or indirect effects on AGL Resources' business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather on the temperature-sensitive portions of the business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; and other factors that are described in detail in our filings with the SEC.

We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in the section Risk Factors in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” among others, could cause our business, results of operations or financial condition in 2006 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors that we cannot anticipate or that are not described in this report 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.**

### Overview

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. 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 also 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 other nonaffiliated companies; natural gas storage arbitrage and related activities; operation of high-deliverability underground natural gas storage assets; and construction and operation of telecommunications conduit and fiber infrastructure within selected 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.

The distribution operations segment is the largest component of our business and is regulated by regulatory agencies in six states. These agencies approve 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 Company (Atlanta Gas Light), our largest utility, the earnings of our regulated utilities are weather sensitive to varying degrees. Although various regulatory mechanisms provide us a reasonable opportunity to recover our fixed costs regardless of natural gas volumes sold, the effect of weather manifests itself in terms of higher earnings during periods of colder weather and lower earnings in warmer weather. Atlanta Gas Light charges rates to its customers primarily on monthly fixed charges. Our retail energy operations segment, which consists of SouthStar Energy Services LLC (SouthStar), also is weather sensitive and uses a variety of hedging strategies to mitigate potential weather impacts. Our Sequent Energy Management, L.P. (Sequent) subsidiary within our wholesale services segment is weather sensitive, with typically increased earnings opportunities during periods of extreme weather conditions.

During the year ended December 31, 2005, we derived approximately 86% of our earnings before interest and taxes (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. For more information regarding our measurement of EBIT, see Results of Operations - AGL Resources.

The remaining 14% 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.

**Our Competitive Strengths**

We believe our competitive strengths have enabled us to grow our business profitably and create significant shareholder value. These strengths include:

***Regulated distribution assets located in growing geographic regions*** Our operations are primarily concentrated along the east coast of the United States, from Florida to New Jersey. We operate primarily urban utility franchises in growing metropolitan areas where we can more effectively deploy technology to improve service delivery and manage costs. We believe the population growth and resulting expansion in business and construction activity in many of the areas we serve should result in increased demand for natural gas and related infrastructure for the foreseeable future.

***Demonstrated track record of performance through superior execution*** We continue to focus our efforts on generating significant incremental earnings improvements from each of our businesses. We have been successful in achieving this goal in the past through a combination of business growth, opportunistic acquisitions and controlling or reducing our operating expenses. We achieved these improvements to our operations in part through the implementation of best practices in our businesses, including increased investments in enterprise technology, workforce automation and business process modernization. Our goal is a single operational platform that eliminates duplicate systems and disparate processes among our various companies.

***Demonstrated ability to acquire and integrate natural gas assets that add significant incremental earnings*** We take a disciplined approach to identifying strategic natural gas assets that support our long-term business plan. For example, our 2004 acquisition of natural gas distribution operations in New Jersey, Florida and Maryland provided us an opportunity to leverage and strengthen one of our core competencies - the efficient, low-cost operation of natural gas franchises. The disparity between these utilities' pre-acquisition utility operating metrics and cost structure and those of our other utilities provided us an opportunity to achieve significant improvements in these businesses, which we have been able to do. We will continue to seek and implement better methods of operating in order to improve our service delivery and reduce our costs. In addition, our acquisition of a natural gas storage facility in Louisiana in 2004 added immediate incremental earnings to our business and, given the possibilities for expansion, has the potential to provide prospective earnings growth.

**Business Accomplishments in 2005**

We believe the results of our efforts are clear. We not only delivered solid results to our shareholders again in 2005 but also provided customers with improved service.

In 2005, we increased net income 26% over the prior year to $193 million and increased fully diluted earnings per share 9% to $2.48 despite increased average outstanding debt of $549 million and 11 million additional shares outstanding in 2005 due to our public stock offering in November 2004, both of which were related to acquisitions in the fourth quarter of 2004. Our Board of Directors raised our annual dividend 19% in November 2005, to an annual rate of $1.48 per share. The increase marked the fourth time in three years our Board has raised the dividend, bringing our payout ratio more in line with other publicly traded energy holding companies and local distribution companies and ensuring a competitive dividend yield relative to alternative investments.

We have substantially completed the integration of our two recent acquisitions: NUI Corporation (NUI), which we acquired on November 30, 2004, and Jefferson Island Storage & Hub, LLC (Jefferson Island), which we acquired on October 1, 2004. Jefferson Island became a wholly owned subsidiary and was renamed Pivotal Jefferson Island Storage & Hub, LLC (Pivotal Jefferson Island). In 2005, we consolidated a number of NUI's business technology platforms into our enterprise-wide systems, including the accounting, payroll, human resources and supply chain functions. We also consolidated the former NUI utility call center operations into our own centralized call center. The combination of systems integration and the application of our operational model to managing NUI has resulted in significant improvements in its operations, as measured by the various metrics we use to manage our business. As a result of these integration efforts, we believe that we have achieved our performance goal of successfully integrating these acquisitions and making them accretive to our consolidated earnings within one year of the acquisition closing date.

We continued business process improvement actions, including the deployment of substantial technology resources, in each of our business units. Additionally, through asset management, producer services and storage arbitrage activities at Sequent, we captured and recognized incremental net income from opportunities in the marketplace as we provided services during and after hurricanes Katrina and Rita. Our operational platform was tested when, during hurricane Rita, Sequent relocated its trading floor from Houston to Richardson, Texas with virtually no service interruptions, in order to keep our commitments to customers and provide continuity in a market where service disruptions were prevalent.

Lastly, we worked cooperatively with our regulators during the year. In Georgia, we negotiated a settlement in the Atlanta Gas Light rate case whereby rates billed to customers will not change for a five-year period but Atlanta Gas Light will recognize reduced operating revenues of $5 million per year for a total of $25 million over the five-year period.

**2006 Goals**

Our fundamental business goals do not significantly change from one year to the next. However, we continue to refine our goals, taking into consideration our prior financial and operational performance and those external factors impacting not only us and the natural gas industry, but also the global marketplace. We are focused on delivering earnings and income growth by effectively managing our gas distribution operations; selectively growing our gas distribution businesses through acquisitions; and developing our portfolio of closely related unregulated businesses.

**Impact of Hurricanes on AGL Resources and Our Industry**

The natural gas production, processing and pipeline infrastructure in the Gulf of Mexico was significantly affected by hurricanes Katrina and Rita in August and September 2005. This resulted in higher prices and increased price volatility for natural gas, which we and the Energy Information Administration expected would significantly increase the cost to heat a home during the current heating season. Natural gas prices moderated by the end of 2005 and early 2006, and weather has been warmer than normal thus far in 2006, but we still expect home heating costs to be significantly higher in the first quarter of 2006 compared to prior years.

The impact of hurricanes Katrina and Rita on natural gas prices and transportation costs created diverse offsetting effects on our business. Increased energy and transportation prices are expected to consume a significantly larger portion of consumer household incomes during the remaining winter heating season (first quarter of 2006), raising the possibility that we will experience some additional bad debt expense, as well as some margin erosion from increased consumer conservation. These higher prices have thus far been mitigated in part by significantly warmer-than-normal temperatures in the eastern United States during the first half of the heating season. While we expect these factors to have some impact on our financial results, primarily in the first half of 2006, we expect the regulatory and operational mechanisms in place in most of our jurisdictions will help mitigate our exposures to high natural gas prices.

Natural gas price volatility during 2005 made it further evident that we and our customers need to diversify our sources of natural gas supply. We receive the majority of our natural gas supplies from a production region in and around the Gulf of Mexico and generally, demand for this natural gas is growing faster than supply. This increased demand can often lead to higher natural gas prices and greater price volatility. We believe a diversification of our supply portfolio, in an effort to moderate prices, is in our customers’ best interest. We may need, from time to time, to invest in new projects to improve the viability of such portfolio diversification and would expect to earn regulated returns on such investments.



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The market dynamics brought on by the two hurricanes presented opportunities for Sequent, and for our utilities through Sequent's affiliate asset management agreements. Sequent drew on its knowledge of the natural gas grid to move gas from supply sources and deliver it to its customers, which involved moving gas over less traditional routes due to Gulf Coast infrastructure limitations. For additional information regarding the impacts of these hurricanes on our business, see Results of Operations - Distribution Operations and Results of Operations - Wholesale Services.

**Regulatory Environment**

We continue to manage the ongoing challenge of operating in a regulatory environment that generally does not measure or reward innovation and operational efficiency. In particular, traditional "cost of service" regulation, which was originally designed to simulate the actions of a competitive market, has not kept pace with the vast changes taking place in the natural gas industry, in technology utilization and in the global economy. These are factors that to various degrees affect our company. The staffs of various state rate setting agencies have argued for significantly lower rates of return on regulated investments without adequate attention to the effects those lower returns might have on capital reinvestment in the company's regulated asset base; the "opportunity cost" to customers of not providing better and more efficient services; and the disincentive for excellence in management and operations that such returns create.

Much of the rate setting is done in adversarial proceedings where rules of evidence and due process can vary greatly among the states.  As a result of these ongoing regulatory challenges, we will continue to work cooperatively with our regulators, legislators and others as we seek, through rate freezes and performance-based rates, to create a framework in each jurisdiction that is conducive to our business goals. Furthermore, we will continue to make strategic investments in energy-related businesses that either are not subject to traditional state and federal rate regulation or are subject to limited oversight in order to add value for our shareholders.

In August 2005, the Energy Policy Act of 2005 (Energy Act) was enacted. The Energy Act authorized many broad energy policy provisions including significant funding for consumers and businesses for energy-related activities, energy-related tax credits, accelerated depreciation for certain natural gas utility infrastructure investments and the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA). The effective date of the PUHCA repeal is February 8, 2006. We continue to evaluate the Energy Act, but we expect to benefit from provisions in the legislation that will support our efforts to promote energy efficiency in a manner that benefits customers and shareholders.

The Energy Act gives the Federal Energy Regulatory Commission (FERC) increased authority over utility merger and acquisition activity, removes many of the geographic and structural restrictions on the ownership of public utilities and eliminates certain regulatory burdens. Some of the SEC reporting requirements, financing authorizations and affiliate relationship approvals that previously applied to us under the PUHCA were replaced by the requirements of the Energy Act.

In addition, the Energy Act requires a public utility holding company to maintain its books and records and make them available to the FERC and to comply with certain reporting requirements. However, the FERC may exempt a class of entities or class of transactions if the FERC finds that they are not relevant to the jurisdictional rate of a public utility or natural gas company.

In February 2006, we requested an exemption from Energy Act oversight of our local distribution companies that were previously exempt from regulation by the FERC. Our filing request will provide us with a temporary exemption. If the FERC has not taken action within 60 days of our request, the exemption shall be deemed to have been granted. We expect to qualify for an exemption from these reporting requirements.

For more information regarding pending federal and state regulatory matters, see Results of Operations - Distribution Operations and Results of Operations - Wholesale Services.

**Results of Operations**

**AGL Resources**

Our results of operations for 2004 included three months of the acquired operations of Jefferson Island and one month of the acquired operations of NUI.

Pursuant to Financial Accounting Standards Board (FASB) Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46) as revised, which we adopted in January 2004, we consolidated SouthStar's accounts with our subsidiaries' accounts as of January 1, 2004. For the years ended December 31, 2005 and 2004, we recorded the Piedmont Natural Gas Company, Inc. (Piedmont) portion of SouthStar's earnings as a minority interest in our statements of consolidated income and the Piedmont portion of SouthStar's contributed capital as a minority interest in our consolidated balance sheets. We eliminated any intercompany profits between segments.

In 2003, we accounted for our 70% noncontrolling financial ownership interest in SouthStar using the equity method of accounting because SouthStar did not meet the definition of a variable interest entity under FIN 46. Under the equity method, we reported our ownership interest in SouthStar as an investment in our consolidated balance sheets, and we reported our share of SouthStar's earnings based on our ownership percentage in our statements of consolidated income as a component of other income.

***Seasonality*** The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season (October - March), natural gas usage and operating revenues are higher because generally more customers are connected to our distribution systems and because natural gas usage is higher in periods of colder weather than in periods of warmer weather. Approximately 70% of these segments' operating revenues and EBIT for the year ended December 31, 2005 were generated during the six-month heating season and are reflected in our consolidated income statements for the quarters ended March 31, 2005 and December 31, 2005. 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.

***Hedging*** Changes in commodity prices subject a significant portion of our operations to variability. Commodity prices tend to be higher in colder months. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with both 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.

Elizabethtown Gas utilizes certain derivatives to hedge the impact of market fluctuations in natural gas prices. These derivative products 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. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, in our consolidated balance sheets.

***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. We record these estimated revenues as unbilled revenues in our consolidated balance sheets.

***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, 2005 and 2004; and pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the year ended December 31, 2003. The unaudited pro-forma results are presented for comparative purposes as a result of our consolidation of SouthStar's accounts with our subsidiaries' accounts as of January 1, 2004. This pro-forma basis is a non-GAAP presentation; however, we believe it is useful to readers of our financial statements since it presents our revenues and expenses for 2003 on the same basis as 2005 and 2004.

| *In millions* | **2005** | **2004** | **Pro-forma 2003** |
|---|---|---|---|
| Operating revenues | $ 2,718 | $ 1,832 | $ 1,557 |
| Cost of gas | 1,626 | 995 | 789 |
| Operating margin | 1,092 | 837 | 768 |
| Operating expenses | | | |
| Operation and maintenance | 477 | 377 | 343 |
| Depreciation and amortization | 133 | 99 | 92 |
| Taxes other than income | 40 | 29 | 28 |
| Total operating expenses | 650 | 505 | 463 |
| Gain on sale of Caroline Street campus | - | - | 16 |
| Operating income | 442 | 332 | 321 |
| Other losses | (1) | - | (6) |
| Minority interest | (22) | (18) | (17) |
| EBIT | 419 | 314 | 298 |
| Interest expense | 109 | 71 | 75 |
| Earnings before income taxes | 310 | 243 | 223 |
| Income taxes | 117 | 90 | 87 |
| Income before cumulative effect of change in accounting principle | 193 | 153 | 136 |
| Cumulative effect of change in accounting principle | - | - | (8) |
| Net income | $ 193 | $ 153 | $ 128 |
| Basic earnings per common share: | | | |
| Income before cumulative effect of change in accounting principle | $ 2.50 | $ 2.30 | $ 2.15 |
| Cumulative effect of change in accounting principle | - | - | (0.12) |
| Basic earnings per common share | $ 2.50 | $ 2.30 | $ 2.03 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Fully diluted earnings per common share: | | | | | | |
| Income before cumulative effect of change in accounting principle | $ | 2.48 | $ | 2.28 | $ | 2.13 |
| Cumulative effect of change in accounting principle | | - | | - | | (0.12) |
| Fully diluted earnings per common share | $ | 2.48 | $ | 2.28 | $ | 2.01 |
| Weighted average number of common shares outstanding: | | | | | | |
| Basic | | 77.3 | | 66.3 | | 63.1 |
| Diluted | | 77.8 | | 67.0 | | 63.7 |

***Segment information*** Operating revenues, operating margin and EBIT information for each of our segments are presented in the following table for the years ended December 31, 2005, 2004 and 2003:

| *In millions* | Operating revenues | Operating margin | EBIT |
|---|---|---|---|
| **2005** | | | |
| Distribution operations | $ 1,753 | $ 814 | $ 299 |
| Retail energy operations | 996 | 146 | 63 |
| Wholesale services | 95 | 92 | 49 |
| Energy investments | 56 | 40 | 19 |
| Corporate (1) | (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 (1) | (185) | (1) | (16) |
| Consolidated | $ 1,832 | $ 837 | $ 314 |
| **2003** | | | |
| Distribution operations | $ 936 | $ 599 | $ 247 |
| Retail energy operations (2) | 743 | 124 | 46 |
| Wholesale services | 41 | 40 | 20 |
| Energy investments | 6 | 5 | (3) |
| Corporate (1) (2) | (169) | - | (12) |
| Consolidated | $ 1,557 | $ 768 | $ 298 |

(1) Includes the elimination of intercompany revenues.

(2) Includes pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts.

In the following table, our reported results in 2003 are reconciled to the pro-forma presentation presented in the tables above. In 2003, we recognized our portion of SouthStar's earnings of $46 million as equity earnings. The amounts presented below for SouthStar represent 100% of its revenues and expenses for 2003 and include minority interest which adjusts our 80% share of SouthStar's earnings to reflect Piedmont's and Dynegy Inc.'s share of SouthStar's earnings.

| | For the twelve months ended December 31, 2003 | | | |
|---|---|---|---|---|
| *In millions* | As Reported | South-Star | Elimin-ations | Pro-Forma |
| Operating revenues | $ 983 | $ 743 | $ (169) | $ 1,557 |
| Cost of gas | 339 | 619 | (169) | 789 |
| Operating margin | 644 | 124 | - | 768 |
| Operating expenses | | | | |
| Operation and maintenance | 283 | 60 | - | 343 |
| Depreciation and amortization | 91 | 1 | - | 92 |
| Taxes other than income | 28 | - | - | 28 |
| Total operating expenses | 402 | 61 | - | 463 |
| Gain on sale of Caroline Street campus | 16 | - | - | 16 |
| Operating income | 258 | 63 | - | 321 |
| Equity earnings from SouthStar | 46 | - | (46) | - |
| Other losses | (6) | - | - | (6) |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Minority interest | | - | | (17) | | - | | (17) |
| EBIT | | 298 | | 46 | | (46) | | 298 |
| Interest expense | | 75 | | - | | - | | 75 |
| Earnings before income taxes | | 223 | | 46 | | (46) | | 223 |
| Income taxes | | 87 | | - | | - | | 87 |
| Income before cumulative effect of change in accounting principle | $ | 136 | $ | 46 | $ | (46) | $ | 136 |

**Discussion of Consolidated Results**

*2005 compared to 2004* Our earnings per share and net income for the year ended December 31, 2005 were higher than the prior year due to the acquisitions of NUI and Jefferson Island combined with strong contributions from our wholesale services and retail energy operations businesses.

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 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. The corporate segment improved by $5 million as compared to last year primarily due to merger and acquisition related costs incurred in 2004 but not in 2005.

Operating margin increased $255 million or 30%, primarily reflecting the NUI and Pivotal 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 $8 million mainly as a result of higher pipeline replacement revenues and additional carrying costs charged to retail marketers in Georgia for gas storage. Retail energy operations' margins were up $14 million, due primarily to higher commodity margins. Wholesale services' operating margin increased $39 million year over year, primarily due to activity during the third and fourth quarters of 2005. Energy investments' margins were also 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.

Operating expenses increased $145 million or 29%, primarily as 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 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 was $109 million, or $38 million higher than in 2004. As indicated in the table below, higher short-term interest rates and higher 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 compared to 2004 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.

| *Dollars 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

We anticipate our interest expense in 2006 will be higher than in 2005 due to higher projected interest rates. Based on $728 million of variable-rate debt, which includes $522 million of our short-term debt, $100 million of variable-rate senior notes and $106 million of variable-rate gas facility revenue bonds outstanding at December 31, 2005, a 100 basis point change in market interest rates from 4.7% to 5.7% would result in an increase in annual pretax interest expense of $7 million.

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. We expect our effective tax rate for the year ending December 31, 2006 to be similar to the effective rate for the year ended December 31, 2005.

As a result of our 11 million share equity offering in November 2004, earnings results for the year are based on weighted average shares outstanding of 77.3 million, while 2004 results were based on weighted average shares outstanding of 66.3 million.

*2004 compared to 2003* Our EBIT for the year ended December 31, 2004 was higher than the prior year due to stronger contributions from our wholesale services business and retail energy operations and from the acquisitions of NUI and Jefferson Island.

Consolidated EBIT for 2004 increased $16 million or 5% as compared to 2003, of which $10 million related to EBIT contributions from our acquisitions of NUI ($7 million) and Jefferson Island ($3 million) during the fourth quarter of 2004. Distribution operations' EBIT for 2004 remained relatively flat as compared to 2003. For comparison purposes, however, distribution operations' EBIT in 2004 increased by $13 million after excluding the effect of a net $13 million pretax gain on the sales of company property and a related charitable contribution in 2003.The increase further reflected increased contributions from SouthStar in retail energy operations of $6 million, AGL Networks in energy investments of $3 million and Sequent in wholesale services of $4 million. Additionally, our energy investments segment had a $4 million increase in EBIT due to the 2004 sale of Heritage Propane and of a residential development property in Savannah, Georgia. These increases were partially offset by lower contributions of $4 million from our corporate segment due to increased outside service costs associated with software maintenance, licensing and implementation of our work management project, higher costs due to Section 404 of the Sarbanes-Oxley Act of 2002 (SOX 404) compliance efforts and merger and acquisition related costs.

Our operating margin for 2004 increased $69 million or 9% as compared to 2003 pro-forma operating margin, primarily reflecting the 2004 NUI and Jefferson Island acquisitions, which contributed $29 million. Sequent, SouthStar and AGL Networks also had improved 2004 operating margins of $13 million, $8 million (on a pro-forma basis) and $2 million, respectively. Excluding the addition of the NUI utilities, distribution operations' margins improved by $17 million mainly at Atlanta Gas Light and Virginia Natural Gas. Atlanta Gas Light's operating margin increased as a result of higher pipeline replacement revenues, additional carrying costs charged to retail marketers in Georgia for gas storage, customer growth and higher customer usage. Virginia Natural Gas' operating margin increased primarily due to customer growth.

Operating expenses increased $42 million on a pro-forma basis or 9% primarily as a result of $19 million in higher expenses due to the additions of NUI and Jefferson Island. In addition, operating expenses at wholesale services increased $9 million due to increased outside service costs related to its energy trading and risk management system and SOX 404 compliance projects and an increase in the number of employees, as well as increased depreciation. Excluding the effects of our acquisition of NUI, distribution operations' expenses increased $10 million as a result of increased costs related to information technology projects, SOX 404 compliance and depreciation expense, offset by decreased bad debt expense. Our corporate segment also had a $6 million increase in operating expenses primarily from increased outside service costs associated with software maintenance, licensing and implementation projects, as well as for SOX 404 compliance efforts and merger and acquisition activities. These increased operating expenses were offset by a $2 million decrease at SouthStar on a pro-forma basis mainly due to lower bad debt expense offset by higher corporate allocated overhead and SOX 404 compliance costs.

Interest expense for 2004 was $71 million or $4 million lower than in 2003. As shown in the following table, a favorable interest rate environment and the issuance of lower-interest long-term debt combined to lower the company's interest expense in 2004 relative to the previous year. The increase of $19 million in average debt outstanding for 2004 compared to 2003 was due to additional debt incurred as a result of the acquisitions of NUI and Jefferson Island.

| *Dollars in millions* | **2004** | **2003** |
|---|---|---|
| Total interest expense | $ 71 | $ 75 |
| Average debt outstanding (1) | 1,274 | 1,255 |
| Average interest rate | 5.6% | 6.0% |

(1) Daily average of all outstanding debt.

The increase in income tax expense of $3 million or 3% for 2004 compared to 2003 reflected $8 million of additional income taxes due to higher corporate earnings year over year, offset by a $5 million decrease in income taxes due to a decrease in the effective tax rate from 39% in 2003 to 37% in 2004. The decline in the effective tax rate was primarily the result of income tax adjustments recorded in the third quarter of 2004 in connection with our annual comparison of filed tax returns to related income tax accruals.

As a result of our 11 million share equity offering in November 2004, earnings results for the year are based on weighted average shares outstanding of 66.3 million, while 2003 results were based on weighted average shares outstanding of 63.1 million.

**Distribution Operations**

Distribution operations includes our natural gas local distribution utility companies that construct, manage and maintain natural gas pipelines and distribution facilities and serve more than 2.2 million end-use customers. The following table provides operational information for our larger utilities. The daily capacity represents total system capability, and the storage capacity includes on-system liquefied natural gas (LNG) and propane volumes.

| | Atlanta Gas Light | Elizabethtown Gas | Virginia Natural Gas | Florida City Gas | Chattanooga Gas |
|---|---|---|---|---|---|
| **Operations** | | | | | |
| Average end-use customers (in thousands) | 1,545 | 266 | 261 | 103 | 61 |
| Daily capacity (1) | 2.5 | 0.4 | 0.4 | 0.1 | 0.2 |
| Storage capacity (1) | 49.4 | 13.6 | 9.6 | - | 3.6 |
| Annual distribution (1) | 232 | 59 | 36 | 10 | 16 |
| 2005 peak day demand (1) | 1.9 | 0.4 | 0.4 | 0.04 | 0.1 |
| Peak storage capacity (1) | 6.2 | 0.1 | 0.8 | - | 1.2 |
| Average monthly throughput (1) | 19.3 | 4.9 | 3.0 | 0.8 | 1.4 |
| Miles of pipeline | 30,427 | 4,948 | 5,106 | 3,162 | 1,521 |
| **Rates** | | | | | |
| Last decision on change in rates | Jun. 2005 | Nov. 2002 | Oct. 1996 | Feb. 2004 | Oct. 2004 |
| Authorized return on rate base | 8.53% | 7.95% | 9.24% | 7.36% | 7.43% |
| Estimated 2005 return on rate base (2) (3) | 8.68% | 6.54% | 8.71% | 6.25% | 7.88% |
| Authorized return on equity | 10.9% | 10.0% | 10.9% | 11.25% | 10.2% |
| Estimated 2005 return on equity (2) (3) | 11.21% | 6.37% | 10.51% | 8.32% | 11.47% |
| Authorized rate base % of equity (4) | 47.9% | 53.0% | 52.4% | 36.8% | 35.5% |
| Rate base included in 2005 return on equity (in millions) (3) (4) | $1,181 | $433 | $321 | $118 | $96 |

(1) In millions of dekatherms.

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

(3) Estimated based on 13-month average.

(4) Rate base for Elizabethtown Gas based on amounts filed in a 2002 rate case; however no specific rate base was authorized due to settlement by stipulation with the New Jersey Board of Public Utilities. A 53% rate base of equity for Elizabethtown Gas was authorized in most recent rate case; however, 50% is used for rate of return calculation purposes based on estimated current regulatory capital structure.

Each utility operates subject to regulations provided by the state regulatory agency in its service territories with respect to rates charged to our customers, maintenance of accounting records, and various other 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 consists generally 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 by making a rate case filing.

***Increased Natural Gas Prices, Bad Debt and Conservation*** Increased prices of natural gas are being driven by increased demand that is exceeding the growth in available supply. The hurricanes in the Gulf Coast region during the late summer and early fall of 2005 impacted the availability of natural gas supply, causing a dramatic rise in natural gas prices. These higher prices have thus far been mitigated in part by significantly warmer-than-normal temperatures in the eastern United States during the first half of the heating season. We expect our customers will incur increases in their bills during the remainder of the current winter heating season.

An increase in the cost of gas due to higher natural gas commodity costs generally has no direct effect on our utility’s net operating margin and net income due to the PGA mechanisms at our utilities. However, net income may be reduced as a result of higher expenses that may be incurred for bad debt, as well as lower volumes of natural gas deliveries to customers due to customer conservation and thus lower natural gas consumption.

These risks of increased bad debt expense and decreased operating margins from conservation are minimized at our largest utility, Atlanta Gas Light, as a result of its straight-fixed-variable rate structure and because customers in Georgia buy gas from certificated marketers rather than from Atlanta Gas Light. Our credit exposure at Atlanta Gas Light is primarily related to the provision of services for the certificated marketers, but that exposure is mitigated because we obtain security support in an amount equal to a minimum of two times a marketer’s highest month’s estimated bill.

As part of our integration strategy, we have implemented measures at our New Jersey and Florida utilities to collect delinquent accounts; these measures are similar to our processes at Virginia Natural Gas and Chattanooga Gas. Across our utility system, bad debt levels are lower year-to-date than they have been in previous years, and we will continue to monitor and mitigate the impact of uncollectible expenses.

We are partnering with regulators and state agencies in each of our jurisdictions to educate customers about these issues, and particularly to ensure that those who qualify for Low Income Home Energy Assistance funds and similar programs receive that assistance.

***Competition*** 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 small commercial markets throughout our service areas and the potential displacement or replacement of natural gas appliances with electric appliances. The primary competitive factors are the price of energy and the desirability of natural gas heating versus alternative heating sources.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer/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

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 in new business and retention. These efforts include working to add residential customers with three or more appliances, 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 leaving our franchise by converting to alternative fuels.

***Atlanta Gas Light*** This natural gas local distribution utility operates distribution systems and related facilities throughout Georgia. Atlanta Gas Light is regulated by the Georgia Public Service Commission (Georgia Commission).

Prior to Georgia’s 1997 Natural Gas Competition and Deregulation Act (Deregulation Act), which deregulated Georgia’s natural gas market, 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 at rates and on terms approved by the Georgia Commission — sell natural gas to end-use customers in Georgia and handle customer billing functions. 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

Since 1998, a number of federal and state proceedings have addressed the role of Atlanta Gas Light in administering and assigning interstate assets to Marketers pursuant to the provisions of the Deregulation Act. In this role, Atlanta Gas Light is authorized to offer additional sales services pursuant to Georgia Commission-approved tariffs and to acquire and continue managing the interstate transportation and storage contracts that underlie the sales services provided to Marketers on its distribution system under Georgia Commission-approved tariffs.

*Rate Settlement Agreement* In June 2005, the Georgia Commission approved a Settlement Agreement with Atlanta Gas Light that froze Atlanta Gas Light's base rates billed to customers as of April 30, 2005 through April 30, 2010. The Settlement Agreement also requires Atlanta Gas Light to recognize reduced revenues of $25 million over the same period, to spend $2 million annually on energy conservation programs and to spend an additional $2 million for social responsibility and education programs. The Settlement Agreement was effective for rates as of May 1, 2005. Atlanta Gas Light offset the impact of the Settlement Agreement on its 2005 EBIT by identifying and implementing reductions in its operating costs and by realizing increased operating margins from net customer growth in 2005.

During the term of the Settlement Agreement, Atlanta Gas Light will not seek a rate increase, nor will the Georgia Commission initiate a new rate proceeding. Atlanta Gas Light will file information equivalent to information that would be required for a general rate case on November 1, 2009, with new rates to be effective on May 1, 2010.

The Settlement Agreement establishes an authorized return on equity of 10.9% for Atlanta Gas Light, resulting in an overall rate of return of 8.53%. Prior to the settlement, Atlanta Gas Light's authorized return on equity was 11% and its overall return was set at 9.16%.

The Settlement Agreement extends Atlanta Gas Light's pipeline replacement program (PRP) by five years to require that all replacements be completed by December 2013 and sets the per-customer PRP rate to be billed at $1.29 per customer per month from May 2005 through September 2008 and at $1.95 from October 2008 through December 2013. Atlanta Gas Light will apply the five-year total reduction in recognized base rate revenues of $25 million to the amount of costs incurred to replace pipe, reducing the amount recovered from customers under the PRP. 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 the remaining 152 miles of cast iron pipe and 70% of the remaining 687 miles of bare steel pipe by December 2010. The remaining 30% of bare steel pipe is required to be replaced by December 2013. The amendment requires an evaluation by Atlanta Gas Light and the Georgia Commission staff of 22 miles of 24-inch pipe in Atlanta by December 2010 to determine if such pipe requires replacement. If replacement of this pipe is required, the pipe must be replaced by December 2013. The additional cost to replace this pipe is projected to be approximately $37 million.

The Settlement Agreement 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.

Atlanta Gas Light will be allowed under the Settlement Agreement to recover through the PRP $4 million of the $32 million in capital costs associated with its March 2005 purchase of 250 miles of pipeline in central Georgia from Southern Natural Gas Company (SNG), a subsidiary of El Paso Corporation. We expect the acquired pipeline to improve deliverable capacity and reliability of the storage capacity from our LNG facility in Macon to our markets in Atlanta. The remaining capital costs are included in Atlanta Gas Light's rate base and collected through base rates.

*Straight-Fixed-Variable Rates* Atlanta Gas Light's revenue is recognized under a straight-fixed-variable rate design whereby Atlanta Gas Light charges rates to its customers based primarily on monthly fixed charges. This mechanism minimizes the seasonality of revenues since the fixed charge is not volumetric and the monthly charges are 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.

***Elizabethtown Gas*** This natural gas local distribution utility operates distribution systems and related facilities 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 is regulated by the New Jersey Board of Public Utilities (NJBPU).

*Weather Normalization* The Elizabethtown Gas tariff contains a weather normalization clause that is designed to help stabilize Elizabethtown Gas 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 weather normalization clause was renewed in October 2004 and is based on a 20-year average of weather conditions.

*Pipeline Replacement* In April 2005, Elizabethtown Gas presented the NJBPU with a proposal to accelerate the replacement of approximately 88 miles of 8" to 12" diameter elevated-pressure cast iron pipe. Under the proposal, approximately $42 million in estimated capital costs incurred over a three-year period would be recovered through a pipeline replacement rider similar to the program in effect at Atlanta Gas Light. If the program as proposed is approved, cost recovery would occur on a one-year lag basis, with collections starting on October 1, 2006 and extending through December 31, 2009, after which time the program would be rolled into base rates. On December 7, 2005, Elizabethtown Gas filed testimony in support of its proposal. The proposal and related testimony will be considered in the following timeframe:

- The New Jersey Rate Payer Advocate will file testimony on February 28, 2006.
- Elizabethtown Gas will file rebuttal testimony on March 17, 2006.
- Public hearings will convene on March 30, 2006.

***Virginia Natural Gas*** This natural gas local distribution utility operates distribution systems and related facilities in southeastern Virginia. Virginia Natural Gas is regulated by the Virginia State Corporation Commission (Virginia Commission).

*Performance-based Rates* In March 2005, the Virginia Commission staff issued a report alleging that Virginia Natural Gas rates were excessive and that its rates should be adjusted to produce a $15 million reduction in revenue. The staff also filed a motion requesting that Virginia Natural Gas rates be declared interim and subject to refund.

In April 2005, Virginia Natural Gas responded to the staff's report and motion, contesting the allegations in the report and objecting to the motion filed by the staff. On April 29, 2005, the Virginia Commission ordered the staff's motion to be held in abeyance and directed Virginia Natural Gas to file a rate case by July 2005.

In July 2005, Virginia Natural Gas filed a performance-based rate (PBR) plan with the Virginia Commission and included the schedules required for a general rate case in support of its proposal. Under the PBR plan, Virginia Natural Gas proposes to freeze base rates at their 1996 levels for 5 additional years. This would provide Virginia Natural Gas customers an additional 5 years of rate stability, for a total of 14 years without a rate increase. If the Virginia Commission approves the proposal, Virginia Natural Gas will become the first Virginia natural gas utility to operate under a 1996 state law that authorized PBR plans for natural gas utilities. Consistent with state law, Virginia Natural Gas has proposed two exceptions that allow for adjustments to frozen base rates. Virginia Natural Gas could request a rate adjustment in connection with (1) any changes in taxation of gas utility revenues by the Commonwealth and (2) any financial distress of Virginia Natural Gas beyond its control.

Based on the Virginia Commission's scheduling order issued on July 14, 2005, current rates will stay in effect until the PBR is decided; consequently, there was no impact on Virginia Natural Gas' 2005 revenues. Based on this scheduling order and the Virginia Commission's approval of requests for extension made by the Virginia Commission staff in December 2005, the PBR proposal to freeze rates for another five years will be considered on the following timeframe:

- Virginia Commission staff filed its testimony and exhibits on January 24, 2006 and requested a $10 million rate decrease
- Virginia Natural Gas filed rebuttal testimony and exhibits on February 7, 2006
- public evidentiary hearings will convene on February 21, 2006

The Virginia state law authorizing PBR plans also allows a utility to withdraw or modify its PBR application at any time prior to a final ruling by the Virginia Commission. Virginia Natural Gas is currently evaluating the withdrawal or modification of its PBR plan in light of current market conditions including rising interest rates, tight natural gas supplies, rising costs and material constraints caused by lower oil supplies. If the PBR plan is not approved or is modified by the Virginia Commission in a manner that Virginia Natural Gas chooses not to accept, the Virginia Commission can take action in the general rate case filing. Virginia Natural Gas' proposal would not affect its Virginia Commission-authorized purchased gas cost, which passes gas commodity costs through to consumers.

On January 12, 2006, Virginia Natural Gas filed with the Virginia Commission a proposed motion for approval of Virginia Natural Gas' PBR plan. If the proposed motion is approved, the PBR plan would be implemented as filed and Virginia Natural Gas would commit to certain actions, primarily to construct a pipeline that would connect Virginia Natural Gas' northern system to its southern system. Participants in and supporters of the proposed motion include Virginia Natural Gas; AGL Resources; the Virginia Office of the Attorney General - Division of Consumer Counsel; and the Virginia Industrial Gas Users' Association. On February 3, 2006, the Virginia Commission's hearing examiner recommended that the Virginia Commission approve the PBR plan. Accordingly, the rate case schedule remains as previously stipulated.

*Weather Normalization Adjustment (WNA)* In September 2002, the Virginia Commission approved a WNA program as a two-year experiment involving the use of special rates. The WNA program'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 winter weather is warmer than normal. 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 significant modifications include 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.

***Florida City Gas*** This natural gas local distribution utility operates distribution systems and related facilities 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 is regulated by the Florida Public Service Commission.

***Chattanooga Gas*** This natural gas local distribution utility operates distribution systems and related facilities in the Chattanooga and Cleveland areas of southeastern Tennessee. Chattanooga Gas' base rates include a weather normalization clause 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. Chattanooga Gas is regulated by the Tennessee Regulatory Authority (Tennessee Authority).

*Base Rate Increase* In June 2005, the Tennessee Authority upheld its previous October 2004 order denying Chattanooga Gas a $4 million rate increase. The October 2004 order approved an increase of approximately $1 million based on a 10.2% return on equity and a capital structure of 35.5% common equity.

***Elkton Gas*** This natural gas local distribution utility operates distribution systems and related facilities serving approximately 5,800 customers in Cecil County, Maryland. Elkton Gas customers are approximately 7% commercial and industrial and 93% residential. Elkton Gas is regulated by the Maryland Public Service Commission.

***Results of Operations*** The following table presents results of operations for distribution operations for the years ended December 31, 2005, 2004 and 2003.

| *In millions* | | **2005** | | **2004** | | **2003** |
|---|---|---|---|---|---|---|
| Operating revenues | $ | 1,753 | $ | 1,111 | $ | 936 |
| Cost of gas | | 939 | | 471 | | 337 |
| Operating margin | | 814 | | 640 | | 599 |
| Operation and maintenance | | 372 | | 286 | | 261 |
| Depreciation and amortization | | 114 | | 85 | | 81 |
| Taxes other than income taxes | | 32 | | 23 | | 24 |
| Total operating expenses | | 518 | | 394 | | 366 |
| Gain on sale of Caroline Street campus | | - | | - | | 21 |
| Operating income | | 296 | | 246 | | 254 |
| Donation to private foundation | | - | | - | | (8) |
| Other income | | 3 | | 1 | | 1 |
| EBIT | $ | 299 | $ | 247 | $ | 247 |
| | | | | | | |
| **Metrics** (1) | | | | | | |
| Average end-use customers (in thousands) | | 2,242 | | 1,880 | | 1,838 |
| Operation and maintenance expenses per customer | $ | 166 | $ | 152 | $ | 142 |
| EBIT per customer (2) | $ | 133 | $ | 131 | $ | 127 |
| Throughput (in millions of Dth) | | | | | | |

| | | | |
|---|---|---|---|
| Firm | 234 | 194 | 190 |
| Interruptible | 120 | 105 | 109 |
| Total | 354 | 299 | 299 |
| Heating degree days (3): | | | |
| Florida | 698 | 239 | - |
| Georgia | 2,726 | 2,589 | 2,654 |
| Maryland | 5,004 | 860 | - |
| New Jersey | 5,017 | 873 | - |
| Tennessee | 3,115 | 3,010 | 3,168 |
| Virginia | 3,465 | 3,214 | 3,264 |

(1) 2004 metrics include only December for Florida City Gas, Elizabethtown Gas and Elkton Gas.

(2) Excludes the gain on the sale of our Caroline Street campus in 2003.

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

*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 full-year inclusion of the NUI results in 2005 compared to 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 for gas stored for Marketers 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 last year.

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

*2004 compared to 2003* There was no change in distribution operations' EBIT from 2003; however, the 2003 results included a pretax gain of $21 million on the sale of our Caroline Street campus, offset by an $8 million donation to AGL Resources Private Foundation, Inc. Exclusive of the gain and donation, EBIT in 2004 increased $13 million or 5% due to increased operating margin, partially offset by increased operating expenses.

The $41 million or 7% increase in operating margin from 2003 included $17 million in combined increases at Atlanta Gas Light and Virginia Natural Gas. The increase in Atlanta Gas Light's operating margin was primarily due to higher PRP revenue as a result of continued PRP capital spending, customer growth, higher customer usage and additional carrying charges from gas stored for Marketers due to a higher average cost of gas. The increase in operating margin at Virginia Natural Gas was primarily due to customer growth. The acquisition of NUI added $24 million of operating margin primarily from NUI's December operations of Elizabethtown Gas and Florida City Gas.

Operating expenses increased $28 million or 8% from 2003. This was due primarily to the addition of NUI operations for the month of December of $17 million. The remaining increase of $11 million was due to increases in the cost of outside services related to increased information technology services as a result of our ongoing implementation of a work management system; increased legal services due to increased regulatory activity; and increased accounting services related to our implementation of SOX 404. Employee benefit and compensation expenses also increased primarily as a result of higher health care insurance costs and increased long-term compensation expenses. In addition, depreciation expenses increased primarily due to new depreciation rates implemented at Virginia Natural Gas and increased assets at each utility. These increases were partially offset by a reduction in bad debt expense, primarily due to a Tennessee Authority ruling that allowed for recovery of the gas portion of accounts written off as uncollectible at Chattanooga Gas and increased collection efforts at both Chattanooga Gas and Virginia Natural Gas.

**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. SouthStar markets natural gas and related services to retail customers on an unregulated basis, principally in Georgia.

The SouthStar executive committee, which acts as the governing board, comprises six members, with three representatives from us 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.

Beginning January 1, 2004, we consolidated the accounts of SouthStar and eliminated all intercompany balances in the consolidation. We recorded the portion of SouthStar's earnings that are attributable to our joint venture partner, Piedmont, as a minority interest in our statements of consolidated income, and we recorded 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 in 2003 through 2005 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 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 which has resulted in significant increases in the cost of natural gas billed to SouthStar's customers.

***Operating Margin*** SouthStar generates its operating margin primarily in two ways. The first is through the sale of natural gas to retail customers in the residential, commercial and industrial sectors, primarily in Georgia. SouthStar captures a spread between wholesale and retail natural gas prices and also realizes a portion of its operating margin through the collection of a monthly service fee and customer late payment fees. SouthStar's operating margins are impacted by weather seasonality as well as by customer growth, and SouthStar's related market share in Georgia, which traditionally ranges from 35% to 38%. SouthStar employs a strategy to attract and retain a higher-quality customer base through the application of stringent credit requirements. This strategy results not only in higher operating margin contributions, as customers tend to utilize higher volumes of natural gas, but also higher EBIT through a reduction in bad debt expenses.

The second way in which SouthStar generates margin is through the optimization of storage and transportation assets. Through its hedging transactions and derivative instruments aimed at managing exposures arising from changing commodity prices, SouthStar utilizes natural gas storage transactions to profit from natural gas pricing differences that occur over time. SouthStar does not hold speculative derivative instruments.

SouthStar is actively seeking to improve its margin-generating capabilities by evaluating a number of growth opportunities, including incremental customer growth in Georgia and expansion of its retail model to other markets, through either organic growth or acquisition of an existing customer portfolio.

***Impact of High Gas Prices*** SouthStar's operating margin and EBIT from the sales of natural gas to retail customers could be affected by conservation and bad debt trends as a result of higher natural gas prices in the 2005 - 2006 winter heating season. SouthStar's bad debt expense as a percentage of operating revenues of approximately 1% for 2005 remained consistent with 2004. We believe SouthStar's higher-quality customer base and the unregulated pricing structure in Georgia mitigates our exposure to higher bad debt expenses.

***Results of Operations*** The following table presents results of operations for retail energy operations for the years ended December 31, 2005 and 2004, and pro-forma results as if SouthStar's accounts were consolidated with our subsidiaries' accounts for the year ended December 31, 2003. The unaudited pro-forma results are presented for comparative purposes as a result of our consolidation of SouthStar in 2004. This pro-forma basis is a non-GAAP presentation; however, we believe it is useful to readers of our financial statements since it presents the revenues and expenses for 2003 on the same basis as 2005 and 2004. In 2003, we recognized our portion of SouthStar's earnings of $46 million as equity earnings.

| *In millions* | **2005** | **2004** | **Pro-forma2003** |
|---|---|---|---|
| Operating revenues | $ 996 | $ 827 | $ 743 |
| Cost of gas | 850 | 695 | 619 |
| Operating margin | 146 | 132 | 124 |
| Operation and maintenance | 58 | 60 | 60 |
| Depreciation and amortization | 2 | 2 | 1 |
| Taxes other than income | 1 | - | - |
| Total operating expenses | 61 | 62 | 61 |
| Operating income | 85 | 70 | 63 |
| Minority interest | (22) | (18) | (17) |
| EBIT | $ 63 | $ 52 | $ 46 |
| | | | |
| **Metrics** | | | |
| Average customers (in thousands) | 531 | 533 | 558 |
| Market share in Georgia | 35% | 36% | 38% |
| Natural gas volumes (billion cubic feet) | 44 | 45 | 49 |

*2005 compared to 2004* The $11 million or 21% increase in EBIT for the year ended December 31, 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 use per customer and lower late payment fees relative to last year.

There was a slight decrease in operating expenses in 2005 compared to 2004. The decrease was due to 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.

*2004 compared to 2003* The increase in EBIT of $6 million or 13% for the year ended December 31, 2004 was primarily the result of higher commodity margins and decreased bad debt expense during the year.

Operating margin for the year increased $8 million or 6%, primarily as a result of a $9 million increase due primarily to a lower commodity cost structure resulting from continued refinement of SouthStar’s hedging strategies and a $3 million increase due to a full year of higher customer service charges from third-party providers. These increases were partially offset by a decrease of $2 million related to a one-time sale of stored gas in 2003 and a $2 million decrease in late payment fees due to an improved customer base.

Operating expenses increased by $1 million or 2% primarily due to a $5 million increase in costs related to SOX 404 implementation and corporate overhead allocations, partially offset by lower bad debt expense resulting from collection process improvements and increased quality of customer base. There was also a $1 million increase in minority interest as a result of higher SouthStar earnings in 2004 compared to 2003.

**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 its customers in the eastern and mid-continental United States with natural gas from the major producing regions and market hubs in the country. Sequent also 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 end-use customers.

***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 services to meet their demands, and they typically contract for these services on a 365-day basis even though they may only need a portion of these services to meet their peak demands. Sequent enters into agreements with these customers, either through contract assignment or agency arrangement, whereby it uses their rights to transportation and storage services during periods when they do not need them. 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.

In April 2005, Sequent commenced asset management responsibilities for Elizabethtown Gas, Florida City Gas and Elkton Gas. In October 2005, the agreement between Sequent and Virginia Natural Gas was renewed for an additional three years. The agreement was scheduled to expire in October 2005. In January 2006, the Georgia Commission extended the asset management agreement between Sequent and Atlanta Gas Light for two additional years. The agreement was scheduled to expire in March 2006. Under the terms of the extended agreement, Sequent will increase its aggregate net sharing percentage paid to Atlanta Gas Light from 50% to 60% on the majority of transactions Sequent will initiate going forward in its role as asset manager. The following table provides additional information on Sequent’s asset management agreements with its affiliated utilities.

| *Dollars in millions* | **Duration of contract** (in years) | **Expiration date** | **Type of fee structure** | **% Shared or annual fee** | **Profit sharing / fees payments 2005** | **2004** | **2003** |
|---|---|---|---|---|---|---|---|
| Elkton Gas | 2 | Mar 2007 | Fixed-fee | (A) | $- | $- | $- |
| Chattanooga Gas | 3 | Mar 2007 | Profit -sharing | 50% | 2 | 1 | - |
| Atlanta Gas Light | 2 | Mar 2008 | Profit -sharing | 60% | 4 | 4 | 3 |
| Elizabethtown Gas | 3 | Mar 2008 | Fixed -fee | $4 | - | - | - |
| Florida City Gas | 3 | Mar 2008 | Profit -sharing | 50% | - | - | - |
| Virginia Natural Gas | 3 | Mar 2009 | Profit -sharing | (B) | 5 | 3 | 5 |

(A) Annual fixed fee is less than $1 million
(B) Sharing is based on a tiered sharing structure

***Transportation and Storage Transactions*** In our wholesale marketing and risk management business, Sequent also contracts for natural gas transportation and storage services. We participate in transactions to manage the natural gas commodity and transportation costs that result in the lowest cost to serve our various markets. We seek 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 we have access and identifying the least-cost alternatives to serve our various markets. This enables us to capture geographic pricing differences across these various markets as delivered gas prices change.

In a similar manner, we participate in natural gas storage transactions where we seek to identify pricing differences that occur over time with regard to future delivery periods at multiple locations. We capture margin by locking in the price differential between purchasing natural gas at the lowest future price and, in a related transaction, selling that gas at the highest future price, all within the constraints of our contracts. Through the use of transportation and storage services, we are able to capture margin through the arbitrage of geographical pricing differences that occur over time.

***Producer Services*** Our 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. We provide producers with certain logistical and risk management services that offer them attractive options to move their supply into the pipeline grid. Aggregating volumes of natural gas from these producers allows us 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 our obligations under these agreements, which are reduced in whole or in part as the matching obligations expire. We will continue to seek new peaking transactions as well as work toward extending those that are set to expire.

***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.

***Seasonality*** Fixed cost commitments are generally incurred evenly over the year, while margins generated through the use of these 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 our business, generally resulting in higher margins in the first and fourth quarters.

***Energy Marketing and Risk Management Activities*** We account for derivative transactions in connection with our energy marketing activities on a fair value basis in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (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 net unrealized losses related to changes in the fair value of derivative instruments utilized in its energy marketing and risk management activities of $30 million during 2005, unrealized gains of $22 million during 2004 and $1 million during 2003. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2005, 2004 and 2003 and provide details of the net fair value of contracts outstanding as of December 31, 2005.

| *In millions* | 2005 | 2004 | 2003 |
|---|---|---|---|
| Net fair value of contracts outstanding at beginning of period | $ 17 | ($5) | $ 7 |
| Cumulative effect of change in accounting principle | - | - | (13) |
| Net fair value of contracts outstanding at beginning of period, as adjusted | 17 | (5) | (6) |
| Contracts realized or otherwise settled during period | (47) | 11 | 2 |
| Change in net fair value of contract gains (losses) | 17 | 11 | (1) |
| Net fair value of new contracts entered into during period | - | - | - |
| Net fair value of contracts outstanding at end of period | (13) | 17 | (5) |
| Less net fair value of contracts outstanding at beginning of period, as adjusted for cumulative effect of change in accounting principle | 17 | (5) | (6) |
| Unrealized (loss) gain related to changes in the fair value of derivative instruments | $ (30) | $ 22 | $ 1 |

The sources of our net fair value at December 31, 2005 are as follows. The “prices actively quoted” category represents Sequent’s positions in natural gas, which are valued exclusively using New York Mercantile Exchange, Inc. (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. Our basis spreads are primarily based on quotes obtained either directly from brokers or through electronic trading platforms.

| *In millions* | Prices actively quoted | Prices provided by other external sources |
|---|---|---|
| Mature through 2006 | ($3) | ($14) |
| Mature 2007 - 2008 | 3 | - |
| Mature 2009 - 2011 | - | 1 |
| Mature after 2011 | - | - |
| Total net fair value | $ - | ($13) |

***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 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.

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 market. The derivatives that Sequent uses to mitigate commodity price risk are accounted for at fair value and marked to market each period. 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.

***Earnings Volatility and Price Sensitivity*** The market dynamics created by the two Gulf Coast hurricanes significantly impacted natural gas prices, primarily in the last five months of 2005. From June 30, 2005 to September 30, 2005, the forward NYMEX prices through March 2006 increased on average approximately $6.10, or 75%. From October 1, 2005 to December 31, 2005, the same prices decreased on average approximately $3.10, or 21%. These market dynamics created significant market opportunities for Sequent, as its storage and transportation activities created increased economic value compared to 2004.

The accounting differences described above also impact 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 2005, Sequent’s reported results were negatively impacted by increases in forward NYMEX prices which resulted in the recognition of unrealized losses. During 2004, the reported results were not as significantly impacted by changes in forward NYMEX prices. As a result, a comparison of the 2005 and 2004 reported results yielded an unfavorable variance during the first nine months of 2005; however, the majority of these unrealized losses were recovered during the fourth quarter of 2005.

***Storage Inventory Outlook*** The following table presents the NYMEX forward natural gas prices as of September 30, 2005 and December 31, 2005 for the period January 2006 through March 2006, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period. January 2006 futures expired on December 28, 2005; however they are included in the table below as they coincide with the January 2006 storage withdrawals. The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. 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.

| | NYMEX forward natural gas prices as of | | | |
|---|---|---|---|---|
| | **Sep 2005** | **Dec 2005** | **$ Change** | **% Change** |
| Jan-06 | $ 14.77 | $ 11.43 | $ (3.34) | (23%) |
| Feb-06 | 14.51 | 11.23 | (3.28) | (23%) |
| Mar-06 | 14.04 | 11.36 | (2.68) | (19%) |
| Avg. | 14.44 | 11.34 | (3.10) | (21%) |

The forward NYMEX prices decreased on average 21% in the fourth quarter of 2005 due to warmer-than-normal weather in late December 2005 and the diminishing effects of hurricanes Rita and Katrina in the fall of 2005. Sequent's original economic profit margin was unaffected by these changes in the NYMEX forward natural gas prices due to the hedging instruments that it has in place. However, the decline in NYMEX prices during the fourth quarter of 2005 resulted in the recovery of previously reported unrealized losses associated with Sequent's NYMEX contracts.

Sequent's expected withdrawals from physical salt dome and reservoir storage are presented in the table below along with its expected gross margin. Sequent's expected gross margin is net of the impact of regulatory sharing and reflects the amounts that we would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at December 31, 2005. Sequent's storage inventory is fully hedged with futures as its 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 increments of 10,000 million British thermal units (MMBtu).

| | **Withdrawal schedule** *(in MMBtu)* | | **Expected gross margin** *(in millions)* (1) |
|---|---|---|---|
| | **Physical salt dome** | **Physical reservoir** | |
| Jan-06 | 119 | 92 | $ 5 |
| Feb-06 | 149 | 212 | 6 |
| Mar-06 | 16 | 252 | 5 |
| Total | 284 | 556 | $ 16 |

(1) After regulatory sharing

The weighted average cost of natural gas in inventory was $9.76 for physical salt dome storage and $8.98 for physical reservoir storage.

As noted above, Sequent's inventory level and pricing as of December 31, 2005 should result in a gross margin of approximately $16 million through March 2006 if all factors remain the same, but could change if Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months.

***Credit Rating*** Sequent has certain trade and credit contracts that have explicit credit rating trigger events in case of a credit rating downgrade. These rating triggers typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, we would need to post collateral to continue transacting with some of our counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, our ability to continue transacting with these counterparties would be impaired. If at December 31, 2005 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 $51 million.

***Results of Operations*** The following table presents results of operations for wholesale services for the years ended December 31, 2005, 2004 and 2003.

| *In millions* | **2005** | **2004** | **2003** |
|---|---|---|---|
| Operating revenues | $ 95 | $ 54 | $ 41 |
| Cost of sales | 3 | 1 | 1 |
| Operating margin | 92 | 53 | 40 |
| Operation and maintenance | 39 | 27 | 20 |
| Depreciation and amortization | 2 | 1 | - |
| Taxes other than income | 1 | 1 | - |
| Total operating expenses | 42 | 29 | 20 |
| Operating income | 50 | 24 | 20 |
| Other loss | (1) | - | - |
| EBIT | $ 49 | $ 24 | $ 20 |
| | | | |
| **Metrics** | | | |
| Physical sales volumes (billion cubic feet / day) | 2.17 | 2.10 | 1.75 |

*2005 compared to 2004* The increase in EBIT of $25 million or 104% in 2005 compared to 2004 was 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 margin was similar to that of the prior year, with quarterly decreases being offset by quarterly increases. However, during the third quarter of 2005, while we created substantial economic value by serving our customers during the storms, our reported operating margin was negatively impacted by accounting losses associated with our storage hedges as a result of increases in forward natural gas prices of approximately $6 per MMBtu. During the fourth quarter, natural gas prices continued to be volatile in the aftermath of the hurricanes and we were able to further optimize our storage and transportation positions at levels in excess of the prior year. In addition, our previously reported hedge losses were partially recovered during the fourth quarter as forward natural gas 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 Sequent's new energy trading and risk management (ETRM) system, which was implemented during the fourth quarter of the prior year.

*2004 compared to 2003* EBIT increased $4 million or 20% from 2003 to 2004 due to a $13 million increase in operating margin, partially offset by a $9 million increase in operating expenses.

Operating margin increased by $13 million or 33% primarily due to increased volatility during the fourth quarter of 2004 which provided Sequent with seasonal trading, marketing, origination and asset management opportunities in excess of those experienced during the prior year. Also contributing to the increase were advantageous transportation values to the Northeast and new peaking and third-party asset management transactions. Sequent's sales volumes for 2004 averaged 2.10 billion cubic feet per day, a 20% increase from the prior year. This increase resulted primarily from the addition of new counterparties, increased presence in the midwestern and northeastern markets and continued growth in origination and asset management activities, as well as business generated due to the market volatility experienced during the fourth quarter.

As a result of a decline in forward NYMEX prices, the 2004 results reflected the recognition of unrealized gains associated with the financial instruments used to economically hedge Sequent’s inventory held in storage. If the forward NYMEX price in effect at December 1, 2004 had also been in effect at December 31, 2004, based on Sequent’s storage positions at December 31, 2004, Sequent’s reported EBIT would have been $19 million. At December 31, 2003, an increase in forward NYMEX prices resulted in the recognition of modest unrealized losses associated with inventory hedges.

Partially offsetting the improved fourth-quarter results was lower volatility during the second quarter of 2004 compared to the same period in 2003, which compressed Sequent's trading and marketing activities and the related margins within its transportation portfolio. In addition, Sequent's weighted average cost of natural gas stored in inventory was $5.06 per MMBtu during the first quarter of 2004 compared to $2.20 per MMBtu during the same period in 2003. This significant difference in cost resulted in reduced operating margins period over period.

Operating expenses increased by $9 million or 45% due primarily to additional salary expense as a result of an increase in the number of employees; additional costs for outside services related to the development and implementation of Sequent's ETRM system; the implementation of SOX 404; and increased corporate costs. In addition, 2004 operating expenses reflected depreciation associated with the recently implemented ETRM system.

**Energy Investments**

***Pivotal 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 Public Service Commission 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 10 million Dth (MMDth) of total capacity and about 7.2 million MMDth of working gas capacity. The facility has approximately 720,000 Dth/day withdrawal capacity and 360,000 Dth/day injection capacity. Pivotal Jefferson Island provides for 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. Our subsidiary Pivotal Energy Development (Pivotal Development) is responsible for day-to-day operation of the facility. Pivotal Jefferson Island is fully subscribed for the 2005-2006 winter period.

In October 2005, Pivotal Jefferson Island also announced that it is soliciting customer interest, in the form of nonbinding bids for capacity, in a project that would expand Pivotal Jefferson Island's salt dome storage facility by 175% from its current capacity of 7.2 MMDth to as much as 19.8 MMDth. The expansion under consideration includes the development of a third and a fourth storage cavern at the facility, with each cavern having a working gas capacity of 6 MMDth. If there is sufficient customer interest in the project, construction would begin in early 2006. We would expect to complete the third cavern by 2009 and would expect the fourth cavern to be operational by 2011. The expansion project also includes expanding the number of pipeline interconnections in order to enhance Pivotal Jefferson Island's flexibility with regard to storage capacity and deliverability. In February 2006, our Board of Directors approved the project and authorized it to go forward. We expect to spend up to approximately $160 million on the expansion project. Pivotal Development's engineering estimates and the need to acquire equipment with appropriate specifications could result in increased costs and delays in the completion of the project.

Pivotal Jefferson Island's competition is limited to other saltdome caverns in the Gulf Coast. We believe that Pivotal Jefferson Island is uniquely situated with its direct connection to the Henry Hub and its connection to seven other pipelines. For these reasons we believe that Pivotal Jefferson Island will be subscribed ahead of most of its competitors.

***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 28,800 Dth of propane air per day on a 10-day-per-year basis to serve Virginia Natural Gas' peaking needs.

***AGL Networks*** This wholly owned subsidiary is a provider of 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 1 to 20 years. In addition, AGL Networks offers telecommunications construction services to companies. AGL Networks' competitors are any entities that have or will lay conduit and fiber on the same route as AGL Networks in the respective metropolitan areas.

***Sale of certain NUI Assets*** In August 2005, we sold our 50% interest in Saltville Gas Storage Company, LLC (Saltville) and associated subsidiaries (Virginia Gas Pipeline and Virginia Gas Storage) to a subsidiary of Duke

Energy Corporation, the other 50% partner in the Saltville joint venture. We acquired these non-utility assets as part of our purchase of NUI in November 2004. We received $66 million in cash at closing, which included $4 million in working capital adjustments, and used the proceeds to repay short-term debt and for other general corporate purposes.

***Results of Operations*** The following table presents results of operations for energy investments for the years ended December 31, 2005, 2004 and 2003.

| *In millions* | **2005** | **2004** | **2003** |
|---|---|---|---|
| Operating revenues | $ 56 | $ 25 | $ 6 |
| Cost of sales | 16 | 12 | 1 |
| Operating margin | 40 | 13 | 5 |
| Operation and maintenance | 17 | 5 | 9 |
| Depreciation and amortization | 5 | 2 | 1 |
| Taxes other than income | 1 | 1 | - |
| Total operating expenses | 23 | 8 | 10 |
| Operating income | 17 | 5 | (5) |
| Other income | 2 | 2 | 2 |
| EBIT | $ 19 | $ 7 | $ (3) |

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*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 Pivotal Jefferson Island; NUI's nonutility businesses, which contributed $8 million; and Pivotal Propane which contributed $3 million. AGL Networks contributed $4 million primarily from growth both in recurring revenues from fiber leasing activities of $1 million and in 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 Pivotal Jefferson Island and $1 million resulted from Pivotal Propane. AGL Networks' operating expenses were relatively flat in 2005 as compared to 2004.

*2004 compared to 2003* The increase in EBIT of $10 million was primarily the result of $3 million from Pivotal Jefferson Island and $3 million from AGL Networks. The remaining increase of $4 million was from the sale of Heritage Propane Partners, L.P. and the sale of a residential and retail development property in Savannah, Georgia in the second quarter of 2004.

Operating margin for the year increased $8 million primarily as a result of the addition of Pivotal Jefferson Island's $4 million of operating margin and an operating margin increase at AGL Networks of $4 million due to increased revenue from a variety of customers.

Operating expenses decreased by $2 million or 20% primarily due to decreased headcount at AGL Networks.

**Corporate**

Our corporate segment includes our nonoperating business units, including AGL Services Company (AGSC), AGL Capital Corporation (AGL Capital) and Pivotal Development. AGSC is a service company established in accordance with the PUHCA. 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 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 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 and AGL Capital's operating expenses and interest costs to our operating segments in accordance with the PUHCA and state 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 Pivotal Jefferson Island, typically will enable 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.

***AGSC Restructuring*** As a result of the NUI acquisition, the associated centralization of certain administrative and operational functions and our ongoing desire to operate as efficiently as possible, we began, during the first quarter of 2005, a review of certain functions within our AGSC subsidiary. We expect this process to be part of an ongoing effort to optimize staffing levels and work processes across our entire company.

The effects of this effort were the restructuring of certain key corporate functions and the elimination of filled and vacant positions within AGSC. We recorded a charge of $3 million in 2005, primarily as a result of severance-related costs associated with the restructuring and elimination of the filled positions at AGSC. Based on efforts performed to date, as well as actual costs incurred to date and our original basis for the earnings guidance previously provided, we estimate the annual savings from these efforts to be in the range of $6 million to $10 million.

***Results of Operations*** The following table presents results of operations for our corporate segment for the years ended December 31, 2005, 2004 and 2003.

| *In millions* | **2005** | **2004** | **2003** |
|---|---|---|---|
| Payroll | $ 57 | $ 48 | $ 48 |
| Benefits and incentives | 34 | 32 | 32 |
| Outside services | 43 | 29 | 19 |
| Taxes other than income | 5 | 4 | 2 |
| Other | 52 | 46 | 44 |
| Total operating expenses before allocations | 191 | 159 | 145 |
| Allocations to operating segments | (185) | (147) | (139) |
| Operating expenses | 6 | 12 | 6 |
| Loss on asset disposed -Caroline Street campus | - | - | (5) |
| Operating loss | (6) | (12) | (11) |
| Other losses | (5) | (4) | (1) |
| EBIT | $ (11) | $ (16) | $ (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.

*2005 compared to 2004* The $5 million or 31% increase in EBIT for 2005 compared to 2004 was primarily due to decreased operating expenses of $6 million. These decreased costs were primarily due to merger- and acquisition-related costs incurred in 2004 but not in 2005. With respect to total operating expenses before allocations, payroll expenses in 2005 increased due to headcount in the corporate segment resulting from the acquisition of NUI in November of 2004 and the realignment and transfer of certain corporate functions to AGSC.

Outside services expenses increased primarily due to higher costs associated with process improvement projects in the information technology, finance and human resources areas.

Benefits and incentives increased primarily as a result of higher payroll-related expenses. In addition, severance expenses increased as a result of the AGSC restructuring and process improvement initiatives.

*2004 compared to 2003* The decrease in EBIT of $4 million or 33% for the year ended December 31, 2004 compared to the same period in 2003 primarily was due to an increase in operating expenses of $6 million. The increase in operating expenses was primarily due to increased outside services costs associated with software maintenance; licensing and implementation of our work management system project; higher costs due to our SOX 404 compliance efforts; merger and acquisition-related expenses; and expenses related to Pivotal Development's activities in 2004. The increase in operating expenses was offset by a loss of $5 million on the sale of our Caroline Street campus in 2003.

**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 supporting credit agreement (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, through February 8, 2006, 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 believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures for the foreseeable future. The relatively stable operating cash flows of our distribution operations businesses currently contribute most of our cash flow from operations, and we anticipate this to continue in the future.

We will continue to evaluate our need to increase our available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by the 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

***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 required pension contributions using the projected unit credit cost method. Under this method, we were not required to make any pension contribution in 2005, but we voluntarily made a $5 million contribution in August 2005. The following table illustrates our expected future contractual obligations as of December 31, 2005.

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | **Payments due before December 31,** | | | | | | |
| *In millions* | | **Total** | | **2006** | | **2007 & 2008** | | **2009 & 2010** | | **2011 & thereafter** |
| Interest charges on outstanding debt (1) | $ | 1,870 | $ | 103 | $ | 201 | $ | 200 | $ | 1,366 |
| Pipeline charges, storage capacity and gas supply (2) (3) | | 1,766 | | 285 | | 515 | | 411 | | 555 |
| Long-term debt (4) | | 1,615 | | - | | 2 | | 2 | | 1,611 |
| Short-term debt | | 522 | | 522 | | - | | - | | - |
| PRP costs (5) | | 265 | | 30 | | 72 | | 95 | | 68 |
| Operating leases (6) | | 160 | | 27 | | 44 | | 33 | | 56 |
| Commodity and transportation charges | | 129 | | 30 | | 19 | | 14 | | 66 |
| Environmental remediation costs (5) | | 97 | | 13 | | 27 | | 53 | | 4 |
| Total | $ | 6,424 | $ | 1,010 | $ | 880 | $ | 808 | $ | 3,726 |

(1) Floating rate debt is based on the interest rate as of December 31, 2005 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. The $38 million allocated to accrued pipeline demand charges in our consolidated balance sheets as of December 31, 2005 represents our estimate of the fair value of the acquired contracts. The liability will be amortized over the remaining lives of the contracts.
(4) Includes $232 million of notes payable to trusts redeemable in 2006 and 2007.
(5) Includes charges recoverable through rate rider mechanisms.
(6) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS No. 13, “Accounting for Leases.” However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

SouthStar has natural gas purchase commitments related to the supply of minimum natural gas volumes to its customers. These commitments are priced on an index plus premium basis. At December 31, 2005, SouthStar had obligations under these arrangements for 8 Bcf for the year ending December 31, 2006. This obligation is not included in the above table. SouthStar also had capacity commitments related to the purchase of transportation rights on interstate pipelines.

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, 2005.

| | | **Commitments due before Dec. 31,** | |
|---|---|---|---|
| *In millions* | **Total** | **2006** | **2007 & thereafter** |
| Standby letters of credit, performance / surety bonds | $ 21 | $ 21 | $ - |

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***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, 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.

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 the 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 2005, our net cash flow provided from operating activities was $78 million, a decrease of $209 million or 73% from the same period last year. 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 of the full year impact associated with the purchase of natural gas for the utilities acquired in November 2004 from NUI, principally for Elizabethtown Gas. These higher natural gas prices resulted in a 45% increase in the average cost of our natural gas inventories.

Our operating cash flow of $287 million for 2004 included SouthStar's operating cash flow of approximately $79 million as a result of our consolidation of SouthStar effective January 1, 2004. In 2003 our operating cash flow only included amounts for cash distributions from SouthStar, consistent with the equity method of accounting. Excluding SouthStar, our cash flow from operations for 2004 was $208 million, an increase of $86 million from 2003. Year-to-year changes in our operating cash flow, excluding SouthStar, were primarily the result of increased earnings of $25 million and decreased spending for injection and purchase of natural gas inventories of $63 million.

***Cash Flow from Investing Activities*** Our investing activities consisted primarily of property, plant and equipment (PP&E) expenditures in 2005, 2004 and 2003 and our acquisitions of NUI for $116 million and Pivotal Jefferson Island for $90 million in 2004. In 2003, our investing activities included our cash payment of $20 million for the purchase of Dynegy Inc.'s 20% interest in SouthStar. The following table provides additional information on our actual and estimated PP&E expenditures.

| *In millions* | **2006** (1) | **2005** | **2004** | **2003** |
|---|---|---|---|---|
| Construction or preservation of distribution facilities | $ 110 | $ 135 | $ 64 | $ 60 |
| SNG pipeline | - | 32 | - | - |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| PRP | | 30 | | 48 | | 95 | | 45 |
| Pivotal Propane plant | | - | | - | | 29 | | - |
| Pivotal Jefferson Island | | 36 | | 8 | | 2 | | - |
| Telecommunications | | 3 | | 1 | | 5 | | 8 |
| Other (2) | | 54 | | 43 | | 69 | | 45 |
| Total | $ | 233 | $ | 267 | $ | 264 | $ | 158 |

(1) Estimated

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

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 a 250-mile pipeline in Georgia from SNG 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 Pivotal 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 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 last year and reduced expenditures of $7 million at Sequent as its ETRM system was implemented in 2004.

Approximately 18% of our PP&E expenditures in 2005 included costs for the PRP, which are approved by the Georgia Commission. In the near term, the primary financial impact to us from the PRP is reduced cash flow from operating and investing activities, as the timing related to cost recovery through Atlanta Gas Light's base rates which include an allowed rate of return on its PRP capital expenditures does not match the timing related to costs incurred.

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) |
|---|---|---|
| 2006 | 95 | $ 30 |
| 2007 | 107 | 35 |
| 2008 | 150 | 37 |
| 2009 | 154 | 45 |
| 2010-2013 | 333 | 118 |
| Totals | 839 | $ 265 |

The increase of $106 million or 67% in PP&E expenditures for 2004 compared to 2003 was primarily due to increased PRP expenditures of $50 million and our construction of the Virginia propane plant by Pivotal Propane for $29 million. Also contributing to the increase were $9 million of expenditures for the construction of the Macon peaking pipeline, $7 million for the ETRM system at Sequent, $2 million at Pivotal Jefferson Island and $3 million at SouthStar.

***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 and the issuance of common stock. 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 by us of the percentage of total debt relative to our total capitalization, as well as the term and interest rate profile of our debt securities.

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 transaction that would require us to issue equity based on credit ratings or other trigger events. As of February 2006, our senior unsecured debt ratings are BBB+ from Standard & Poor's Ratings Services (S&P), Baa1 from Moody's Investors Service (Moody's) and A- from Fitch Ratings (Fitch).

In July 2004 upon the announcement of our proposed acquisition of NUI, S&P placed our credit ratings on CreditWatch with negative implications, Moody's affirmed our ratings but changed its rating outlook to negative from stable, and Fitch placed our credit ratings on Rating Watch Negative. Since the closing of the acquisition on November 30, 2004, S&P removed us from CreditWatch and changed our outlook to negative; Fitch took us off Rating Watch Negative and affirmed our ratings with a stable outlook; and Moody's changed our outlook to stable. S&P has indicated that the negative outlook is the result of the execution risks in integrating the NUI acquisition.

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 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% of debt to total capitalization. We are currently in compliance with all existing debt provisions and covenants. For more information on our debt, see Note 9.

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.

| *Dollars 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% |

| *Dollars in millions* | | **Dec. 31, 2004** | |
|---|---|---|---|
| Short-term debt | $ | 334 | 10% |
| Long-term debt (1) | | 1,623 | 49 |
| Total debt | | 1,957 | 59 |
| Common shareholders' equity | | 1,385 | 41 |
| Total capitalization | $ | 3,342 | 100% |

(1) Net of interest rate swaps.

*Short-term debt* Our short-term debt is composed of borrowings under our commercial paper program, Sequent's lines of credit, SouthStar's line of credit 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.

Our Credit Facility was amended in August 2005. Under the terms of the amendment, the term of the Credit Facility was extended to August 31, 2010. The aggregate principal amount available under the amended Credit Facility was increased to $850 million, with an option to increase the aggregate cumulative principal amount available for borrowing to $1.1 billion on not more than three occasions during each calendar year. 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 represented in the table below.

| *In millions* | | **Dec. 31, 2005** | | **Dec. 31, 2004** |
|---|---|---|---|---|
| Unused availability under the Credit Facility | $ | 850 | $ | 750 |
| Cash and cash equivalents | | 30 | | 49 |
| Total cash and available liquidity under the Credit Facility | $ | 880 | $ | 799 |

As of December 31, 2005 and 2004, 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

- maintain 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 June 2005, Sequent's existing $25 million unsecured line of credit was extended to July 2006. In September 2005, Sequent entered into an agreement for an additional $20 million unsecured line of credit scheduled to expire in September 2006. These unsecured lines of credit, which total $45 million, are used solely for the posting of margin deposits for NYMEX transactions, and are unconditionally guaranteed by us. At December 31, 2005, there were no outstanding amounts under these lines of credit, which is an $18 million decrease from the same time in 2004.

In September 2005, Pivotal Utility Holdings, Inc entered into an agreement for a $20 million unsecured line of credit to be used solely for the posting of margin deposits for Elizabethtown Gas' natural gas hedging program. The line expires in September 2006 and is unconditionally guaranteed by us. There were no amounts outstanding under this line of credit at December 31, 2005.

SouthStar's $75 million line of credit provides the additional working capital needed to meet seasonal demands and is not guaranteed by us. This line of credit is secured by various percentages of its accounts receivable, unbilled revenue and inventory. The line of credit expires in April 2007 and bears interest at the prime rate and/or LIBOR plus a margin based on certain financial measures. At December 31, 2005, the line of credit had an outstanding balance of $36 million. There were no amounts outstanding under this facility at the same time in 2004.

In 2004, we repaid $500 million outstanding under NUI's credit facility. Upon the repayment of the outstanding amounts, we terminated NUI's credit facility.

*Long-term Debt* In 2004, AGL Capital issued $250 million of 6% Senior Notes Due October 2034 and $200 million of 4.95% Senior Notes Due January 2015. We fully and unconditionally guarantee the senior notes. The proceeds from the issuance were used to refinance a portion of our outstanding short-term debt under our commercial paper program.

During 2004, we also made $82 million in medium-term note payments using proceeds from the borrowings under our commercial paper program. For more information on our long-term debt, including the debt assumed in the NUI acquisition, see Note 9.

*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. At December 31, 2005, including the effects of $100 million of interest rate swaps, 66% of our total short-term and long-term debt was fixed.

*Refinancing of Gas Facility Revenue Bonds* In April and May 2005, we refinanced $67 million of our gas facility revenue bonds. For more information, see Note 9.

*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 $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.

*Common Stock* In November 2004, we completed our public offering of 11.04 million shares of common stock, generating net proceeds of approximately $332 million. We used the proceeds to purchase the outstanding capital stock of NUI and to repay short-term debt incurred to fund our purchase of Jefferson Island.

*Dividends on Common Stock* 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 2004, we made $75 million in common stock dividend payments. This was an increase of $5 million or 7% from 2003. The increase was due to our 6.4 million common stock offering in February 2003, 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 9.

| 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 |
| Apr 2003 | 4 | 0.28 | 1.12 |

*Shelf Registration* We currently have remaining capacity under an October 2004 shelf registration statement of approximately $957 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 (PRP)*** 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 initially identified, and provided notice to the Georgia Commission in accordance with this stipulation, 2,312 miles of bare steel and cast iron pipe to be replaced. Atlanta Gas Light had subsequently identified an additional 320 miles of pipe subject to replacement under this program.

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 152 miles of cast iron and 687 miles of bare steel pipe still require replacement. The amendment also requires an evaluation by Atlanta Gas Light and the Georgia Commission staff of 22 miles of 24-inch pipe in Atlanta by December 2010 to determine if such pipe requires replacement. If replacement of this pipe is required, the pipe must be replaced by December 2013. The additional cost to replace this pipe is projected to be approximately $37 million. 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.

The stipulation 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. 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 and remaining footage of infrastructure to be replaced for the remaining years of the program. Atlanta Gas Light recorded a long-term liability of $235 million as of December 31, 2005 and $242 million as of December 31, 2004, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2005, Atlanta Gas Light had recorded a current liability of $30 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, 2005 for those elements of the remediation program with in-place contracts or engineering cost estimates is $12 million for Atlanta Gas Light's Georgia and Florida sites. This is a reduction of $24 million from the estimate as of December 31, 2004 of projected engineering and in-place contracts, resulting from program expenditures during 2005. 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 $15 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. Through January 2007, Atlanta Gas Light estimates the administration costs to be $4 million. Beyond 2007, these costs are not estimable.

Atlanta Gas Light's environmental remediation liability is included in its corresponding regulatory asset. As of December 31, 2005, the regulatory asset was $133 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 $57 million to $104 million. As of December 31, 2005, no value within this range is better than any other value, so we recorded a liability of $57 million.

The NJBPU 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 $63 million, inclusive of interest, as of December 31, 2005, 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, 2005, 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 Energy and Natural Resources. We do not have precise estimates for the cost of investigating and remediating this site, although preliminary estimates for these costs range from $10 million to $17 million. As of December 31, 2005, we have 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.

***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 other comprehensive income (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. Two areas where SFAS 133 applies are interest rate swaps and gas commodity contracts at Sequent and SouthStar. Our derivative and hedging activities are described in further detail in Note 4.

*Interest Rate Swaps* We designate our interest rate swaps as fair value hedges as defined by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. 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. The effect of this accounting is to reflect in earnings only that portion of the hedge that is not effective in achieving offsetting changes in fair value.

*Commodity-related Derivative Instruments* We are exposed to risks associated with changes in the market price of natural gas. Elizabethtown Gas utilizes certain derivatives for nontrading purposes to hedge the impact of market fluctuations on assets, liabilities and other contractual commitments. Pursuant to SFAS 133, such derivative products are marked to market each reporting period. Pursuant to regulatory requirements, realized gains and losses related to such derivatives are reflected in purchased gas costs and included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, in the consolidated balance sheet. 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.

Under our risk management policy, 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 on an accrual basis, at the lower of average cost or market, classified as inventory in our consolidated balance sheets; it is no longer marked to market following our implementation of the accounting guidance in EITF 02-03. 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 accrual basis for our storage inventory versus mark-to-market accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported net income.

Over time, gains or losses on the sale of storage inventory will be 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. Sequent manages underground storage for our utilities and holds certain capacity rights on its own behalf. The underground storage is of two types:

- reservoir storage, where supplies are generally injected and withdrawn on a seasonal basis
- salt dome high-deliverability storage, where supplies may be periodically injected and withdrawn on relatively short notice

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, 2005, the ending balance in OCI for derivative transactions designated as cash flow hedges under SFAS 133 was $(0.8) million. 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.

***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 assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligations and net pension and postretirement cost. When establishing our discount rate, we consider absolute high quality corporate bond rates based on Moody's Corporate AA long-term bond rate of 5.41% and the Citigroup Pension Liability rate of 5.51% at December 31, 2005. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors.

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 utilized in calculating 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 the 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 upon 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 our 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 $6 million. A one point percentage point decrease in the assumed health care cost trend rate would decrease our accumulated projected benefit obligation by $5 million. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

At December 31, 2005, we had an increase in our minimum pension liability by approximately $8 million, resulting in an after-tax loss to OCI of $5 million. This adjustment reflected our funding contributions to the plan and updated valuations for the projected benefit obligation and plan assets. To the extent that our future expenses and contributions increase as a result of the additional minimum pension liability, we believe that such increases are recoverable in whole or in part under future rate proceedings or mechanisms.

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 the 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.

A one-percentage-point increase in the assumed discount rate would decrease the AGL Resources Inc. Retirement Plan's ABO by approximately $39 million and decrease annual pension expense by approximately $4 million. A one-percentage-point decrease in the assumed discount rate would increase the AGL Resources Inc. Retirement Plan's ABO by approximately $44 million and increase annual pension expense by approximately $4 million. Additionally, a one-percentage-point increase or decrease in the expected return on assets would decrease or increase the AGL Resources Inc. Retirement Plan's annual pension expense by approximately $3 million.

Additionally, in 2004 we recorded a $36 million liability for the amount of NUI's projected benefit obligation in excess of the fair value of pension plan assets at the date of our acquisition of NUI. At December 31, 2005 our accrued liability for NUI's projected obligation is $31 million, reflecting $9 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 2005. A one-percentage-point increase in the assumed discount rate would decrease the NUI Corporation Retirement Plan's ABO by approximately $14 million and decrease annual benefit cost by approximately $2 million. A one-percentage-point decrease in the assumed discount rate would increase the NUI Corporation Retirement Plan's ABO by approximately $17 million and increase annual pension expense by approximately $1 million. In addition, a one-percentage-point increase or decrease in the NUI Corporation Retirement Plan's expected return on assets would decrease or increase annual pension expense by approximately $1 million.

As of December 31, 2005, the market value of the pension assets was $371 million compared to a market value of $390 million as of December 31, 2004. The net decrease of $19 million resulted from

- contributions of $5 million in August 2005
- contributions of $1 million in 2005 to our supplemental retirement plan
- an actual return on plan assets of $27 million less benefits paid of $52 million

Our $5 million in contributions to the pension plan in 2005 reduced annual pension expense by approximately $0.4 million in 2005. The actual return on plan assets compared to the expected return on plan assets will have an impact on our benefit obligation as of December 31, 2005 and our pension expense for 2006. We are unable to determine how this actual return on plan assets will affect future benefit obligation 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, 2005. Our actual returns may also be positively or negatively impacted as a result of future performance in the equity and bond markets.

**Accounting Developments**

For information regarding accounting developments, see Note 3.

## RISK FACTORS

*The following are some of the factors that could affect our future performance or could cause actual results to differ materially from those expressed or implied in our forward-looking statements. We cannot predict every event and circumstance that may adversely affect our business, but the risks and uncertainties described below are the most significant factors that we have identified at this time.*

**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 have been regulated by the SEC under the PUHCA and, effective February 8, 2006 will be regulated by the FERC under the PUHCA 2005. At the state level, our distribution businesses are regulated by the Georgia Commission, the Tennessee Authority, the NJBPU, the Florida Commission, the Virginia Commission and the Maryland Commission. These authorities regulate many aspects of our distribution operations, including construction and maintenance of facilities, operations, safety, rates that we can charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs, carrying costs we charge Marketers for gas held in storage for their customer accounts and relationships with our affiliates. 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.

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. 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. Gas 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 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.

**We have a concentration of credit risk in Georgia, which could expose a significant portion of our accounts receivable to collection risks.**

We have a concentration of credit risk related to the provision of natural gas services to Georgia Marketers. At September 30, 1998 (prior to deregulation), Atlanta Gas Light had approximately 1.4 million end-use customers in Georgia. In contrast, at December 31, 2005, Atlanta Gas Light had only 10 certificated and active Marketers in Georgia, four of which (based on customer count and including SouthStar) accounted for approximately 33% of our consolidated operating margin for 2005. 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. Additionally, SouthStar markets directly to end-use customers and has periodically experienced credit losses as a result of cold weather, variable prices and customers’ inability to pay.

**The cost of providing pension and postretirement health care benefits to eligible former employees 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.

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

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 our systems in favor of special competitive contracts with lower per-unit costs or disconnect from our system.

**Our wholesale services segment competes with larger, full-service energy providers, which may limit our ability to grow our business.**

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.

**Our asset management arrangements between Sequent and our affiliated 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, Virginia Natural Gas, Florida City Gas and Chattanooga Gas and shares profits it earns from the management of those assets with those customers and their customers, except at Elizabethtown Gas and Elkton Gas where Sequent is assessed an annual fixed fee payment. In addition, Sequent has asset management agreements with certain nonaffiliated customers. Entry into and renewal of these agreements are subject to regulatory approval. Sequent's results could be significantly impacted if these agreements are not renewed or are amended or renewed with less favorable terms.

**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.

**We have a concentration of credit risk at Sequent that could expose us to collection risks.**

We often extend credit to our counterparties. Despite performing credit analyses prior to extending credit and seeking to effectuate netting agreements, we are exposed to the risk that we may not be able to collect amounts owed to us. If the counterparty to such a transaction fails to perform and any collateral we have secured is inadequate, we could experience material financial losses.

We have a concentration of credit risk at Sequent, which could expose a significant portion of our credit exposure to collection risks. Approximately 52% 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 are exposed to market risk and may incur losses in wholesale services.**

The commodity, storage and transportation portfolios at Sequent 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 and a 10-day holding period for all positions, Sequent's portfolio of positions as of December 31, 2005 had a 1-day holding period VaR of $0.6 million and 10-day holding period VaR of $1.9 million.

**Our accounting results may not be indicative of the risks we are taking or the economic results we expect due to changes in accounting 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 match up with 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.

**Our business is subject to environmental regulation in all jurisdictions in which we operate and our costs to comply are significant, and 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 and/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 in the Southeast, we manufactured gas from coal and other fuels. Those manufacturing operations were known as manufactured gas plants, or MGPs, which we ceased operating in the 1950s.

We have identified 10 sites in Georgia and 3 in Florida where we, or our predecessors, own or owned all or part of a MGP site. We are required to investigate possible environmental contamination at those MGP sites and, if necessary, clean up any contamination. To date, cleanup has been completed at these sites, and as of December 31, 2005, the soil and sediment remediation program was complete for all Georgia sites, although groundwater cleanup continues. As of December 31, 2005, projected costs associated with the MGP sites were $31 million. For elements of the MGP program where we still cannot provide engineering cost estimates, considerable variability remains in available 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 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 $57 million to $104 million. Costs have been estimated for only 1 of the non-New Jersey sites, for which current estimates range from $10 million to $17 million.

**Our growth may be restricted by the capital-intensive nature of our business.**

We must construct additions to our natural gas distribution system each year to continue the expansion of our customer base. The cost of this construction may be affected by the cost of obtaining government approvals, development project delays or changes in project costs. Weather, general economic conditions and the cost of funds to finance our capital projects can materially alter the cost of a project. Our cash flows are not fully adequate to finance the cost of this construction. As a result, we must fund a portion of our cash needs through borrowings and the issuance of common stock. This may limit our ability to increase infrastructure to connect customers due to limits on the amount we can economically invest, which shifts costs to potential customers. This may make it uneconomical for these potential customers to connect to our distribution systems.

**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 the cost of natural gas.

We have a WNA mechanism for Elizabethtown Gas, Chattanooga Gas and Virginia Natural Gas that partially offsets the impact of unusually cold or warm weather on residential and commercial customer billings and margin. 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.

**Inflation and increased gas costs could adversely impact our customer base and customer collections and increase our level of indebtedness.**

Inflation has caused increases in certain operating expenses and has required us to replace assets at higher costs. 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 intend to continue to do so. The ability to control expenses is an important factor that will influence 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 also results in higher short-term debt levels and increased bad debt expense. Should the price of purchased gas increase significantly in the upcoming heating season, we would expect increases in our short-term debt, accounts receivable and bad debt expense during 2006.

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 products utilizing energy sources other than natural gas for applications that have traditionally used natural gas to be in more competitive position, 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.

<u>**Risks Related to Our Corporate and Financial Structure**</u>

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

Our existing debt and the debt of certain of our subsidiaries contain a number of significant financial covenants. If we or any of these subsidiaries 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 Facility and the indenture under which Atlanta Gas Light's outstanding medium-term notes were 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.

**We depend on our ability to successfully access the capital 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 in Georgia
- significant decrease in the demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies
- terrorist attacks on our facilities or our suppliers
- extreme weather conditions

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

S&P, Moody's and Fitch currently assign our senior unsecured debt a rating of BBB+, Baa1 and A-, respectively. Our commercial paper currently is rated A-2, P-2 and F-2 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, 2005, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $51 million to continue conducting our wholesale services business with certain counterparties.

**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.

**We are vulnerable to interest rate risk with respect to our debt, which could lead to changes in interest expense.**

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.

**Risks Related to Our Industry**

**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.

## 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 senior executives who monitor commodity price risk positions, 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 4.

### Commodity Price Risk

***Retail Energy Operations*** SouthStar's use of derivatives is governed by a risk management policy, created and monitored by its risk 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 and 10-day holding period VaR.

| *In millions* | **1-day** | **10-day** |
|---|---|---|
| 2005 period end | $ 0.3 | $ 0.8 |
| 2004 period end | 0.2 | 0.5 |

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 spreads between wholesale and retail commodity prices widen between periods) and thereby minimize its exposure to declining operating margins.

***Wholesale Services*** This segment 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 our energy marketing and risk management assets and liabilities as of December 31, 2005 and 2004. We base the average values on monthly averages for the 12 months ended December 31, 2005 and 2004.

| *In millions* | Average values at December 31, 2005 | 2004 |
|---|---|---|
| Asset | $ 83 | $ 28 |
| Liability | 102 | 21 |

| *In millions* | Value at December 31, 2005 | 2004 |
|---|---|---|
| Asset | $ 97 | $ 36 |
| Liability | 110 | 19 |

We employ a systematic approach to evaluating and managing the risks associated with our contracts related to wholesale marketing and risk management, including VaR. Similar to SouthStar, Sequent uses a 1-day and a 10-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 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.

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 sell volume, with minimal open commodity risk. Based on a 95% confidence interval and employing a 1-day and a 10-day holding period for all positions, Sequent's portfolio of positions for the 12 months ended December 31, 2005, 2004 and 2003 had the following 1-day and 10-day holding period VaRs.

| *In millions* | 1-day | 10-day |
|---|---|---|
| 2005 | | |
| Period end | $ 0.6 | $ 1.9 |
| 12-month average | 0.4 | 1.2 |
| High | 1.1 | 3.5 |
| Low (1) | 0.0 | 0.0 |
| | | |
| 2004 | | |
| Period end | $ 0.1 | $ 0.2 |
| 12-month average | 0.1 | 0.3 |
| High | 0.4 | 1.3 |
| Low (1) | 0.0 | 0.0 |
| | | |
| 2003 | | |
| Period end | $ 0.3 | $ 1.0 |
| 12-month average | 0.1 | 0.3 |
| High | 2.5 | 4.7 |
| Low (1) | 0.0 | 0.0 |

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

During 2005 Sequent experienced increases in its high, 12-month average and period end 1-day and 10-day VaR amounts. These increases were directly associated with the market impacts and related price volatility created by the

Gulf Coast hurricanes during the third quarter and the lingering effects through year end.

**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 2011.

At the beginning of 2005, we had $75 million of outstanding interest rate swap agreements associated with our note payable at AGL Capital Trust II. On September 7, 2005, we terminated these interest rate swap agreements. We received a payment of $1 million related to this termination, which included accrued interest and the fair value of these interest rate swap agreements at the termination date.

In September 2005, we also executed five treasury-lock agreements totaling $125 million to hedge the interest rate risk associated with an anticipated 2006 financing. The agreements will result in a 4.11% interest rate on the 10-year United States Treasury bond against which we will be measured in issuing our own debt instruments and were designated as cash flow hedges against the future interest payments on the anticipated financing.

**Credit Risk**

***Distribution Operations*** Atlanta Gas Light has a concentration of credit risk because it bills only 10 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. These Marketers, in turn, bill end-use customers. 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 2005, the 4 largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 33% of our consolidated operating margin and 45% 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.

***Retail Energy Operations*** SouthStar credit-scores firm residential and small commercial customers using a national credit reporting agency and enrolls, without security, only those customers that meet or exceed SouthStar's credit threshold. The average credit score of SouthStar's Georgia customers has increased 9% since 2003.

SouthStar investigates potential interruptible and large commercial customers through reference checks, 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 their 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, 2005, Sequent's top 20 counterparties represented approximately 52% of the total counterparty exposure of $554 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of December 31, 2005, 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, 2005 and 2004.

| | As of: December 31, | |
|---|---|---|
| *In millions* | **2005** | **2004** |
| **Gross receivables** | | |
| Receivables with netting agreements in place: | | |
| Counterparty is investment grade | $ 462 | $ 378 |
| Counterparty is non-investment grade | 66 | 36 |
| Counterparty has no external rating | 113 | 78 |
| Receivables without netting agreements in place: | | |
| Counterparty is investment grade | 34 | 16 |
| Counterparty is non-investment grade | - | 6 |
| Counterparty has no external rating | - | - |
| Amount recorded on balance sheet | $ 675 | $ 514 |
| | | |
| **Gross payables** | | |
| Payables with netting agreements in place: | | |
| Counterparty is investment grade | $ 456 | $ 291 |
| Counterparty is non-investment grade | 56 | 45 |
| Counterparty has no external rating | 255 | 139 |
| Payables without netting agreements in place: | | |
| Counterparty is investment grade | 4 | 40 |
| Counterparty is non-investment grade | - | 6 |
| Counterparty has no external rating | 4 | - |
| Amount recorded on balance sheet | $ 775 | $ 521 |

Sequent has certain trade and credit contracts that have explicit rating trigger events in case of a credit rating downgrade. These rating triggers 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, 2005 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 $51 million.

**ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA**

**AGL Resources Inc.**
**Consolidated Balance Sheets - Assets**

| *In millions* | As of: December 31, 2005 | December 31, 2004 |
|---|---|---|
| **Current assets** | | |
| Cash and cash equivalents | $ 30 | $ 49 |
| Receivables | | |
| Energy marketing | 675 | 514 |
| Gas | 303 | 180 |
| Unbilled revenues | 246 | 189 |
| Other | 11 | 21 |
| Less allowance for uncollectible accounts | (15) | (15) |
| Total receivables | 1,220 | 889 |
| Inventories | | |
| Natural gas stored underground | 509 | 320 |
| Other | 34 | 12 |
| Total inventories | 543 | 332 |
| Energy marketing and risk management assets | 103 | 44 |
| Unrecovered environmental remediation costs - current portion | 31 | 27 |
| Unrecovered pipeline replacement program costs - current portion | 27 | 24 |
| Other current assets | 78 | 89 |
| Total current assets | 2,032 | 1,454 |
| **Property, plant and equipment** | | |
| Property, plant and equipment | 4,791 | 4,615 |
| Less accumulated depreciation | 1,520 | 1,437 |
| Property, plant and equipment - net | 3,271 | 3,178 |
| **Deferred debits and other assets** | | |
| Goodwill | 422 | 354 |
| Unrecovered pipeline replacement program costs | 276 | 337 |
| Unrecovered environmental remediation costs | 165 | 173 |
| Other | 85 | 141 |
| Total deferred debits and other assets | 948 | 1,005 |
| **Total assets** | $ 6,251 | $ 5,637 |

See Notes to Consolidated Financial Statements.

**AGL Resources Inc.**
**Consolidated Balance Sheets - Liabilities and Capitalization**

| *In millions, except share amounts* | As of: December 31, 2005 | December 31, 2004 |
|---|---|---|
| **Current liabilities** | | |
| Energy marketing trade payable | $ 775 | $ 521 |
| Short-term debt | 522 | 334 |
| Accounts payable - trade | 264 | 207 |
| Energy marketing and risk management liabilities - current portion | 101 | 15 |
| Customer deposits | 42 | 50 |
| Accrued wages and salaries | 43 | 49 |
| Accrued interest | 32 | 28 |
| Deferred purchased gas adjustment | 36 | 60 |
| Accrued pipeline replacement program costs - current portion | 30 | 85 |
| Accrued environmental remediation costs - current portion | 13 | 27 |
| Other current liabilities | 81 | 98 |
| Total current liabilities | 1,939 | 1,474 |
| **Accumulated deferred income taxes** | 423 | 437 |
| **Long-term liabilities** | | |
| Accrued pipeline replacement program costs | 235 | 242 |
| Accrued postretirement benefit costs | 54 | 58 |
| Accumulated removal costs | 94 | 94 |
| Accrued environmental remediation costs | 84 | 63 |
| Accrued pension obligations | 88 | 84 |
| Other long-term liabilities | 182 | 141 |
| Total long-term liabilities | 737 | 682 |
| **Commitments and contingencies (see Note 10)** | | |
| **Minority interest** | 38 | 36 |
| **Capitalization** | | |
| Long-term debt | 1,615 | 1,623 |
| Common shareholders' equity, $5 par value; 750 million shares authorized; 77.7 million and 76.7 million shares outstanding at December 31, 2005 and 2004 | 1,499 | 1,385 |
| Total capitalization | 3,114 | 3,008 |
| **Total liabilities and capitalization** | $ 6,251 | $ 5,637 |

See Notes to Consolidated Financial Statements.

**AGL Resources Inc.**
**Statements of Consolidated Income**

| *In millions, except per share amounts* | Years ended December 31, 2005 | 2004 | 2003 |
|---|---|---|---|
| Operating revenues | $ 2,718 | $ 1,832 | $ 983 |
| Operating expenses | | | |
| Cost of gas | 1,626 | 995 | 339 |
| Operation and maintenance | 477 | 377 | 283 |
| Depreciation and amortization | 133 | 99 | 91 |
| Taxes other than income taxes | 40 | 29 | 28 |
| Total operating expenses | 2,276 | 1,500 | 741 |
| Gain on sale of Caroline Street campus | - | - | 16 |
| Operating income | 442 | 332 | 258 |
| Equity in earnings of SouthStar Energy Services LLC | - | - | 46 |
| Other losses | (1) | - | (6) |
| Minority interest | (22) | (18) | - |
| Interest expense | (109) | (71) | (75) |
| Earnings before income taxes | 310 | 243 | 223 |
| Income taxes | 117 | 90 | 87 |
| Income before cumulative effect of change in accounting principle | 193 | 153 | 136 |
| Cumulative effect of change in accounting principle, net of $5 in taxes | - | - | (8) |
| Net income | $ 193 | $ 153 | $ 128 |
| Per Common Share Data | | | |
| Basic | | | |
| Income before cumulative effect of change in accounting principle | $ 2.50 | $ 2.30 | $ 2.15 |
| Cumulative effect of change in accounting principle | - | - | (0.12) |
| Basic earnings per common share | $ 2.50 | $ 2.30 | $ 2.03 |
| Fully diluted | | | |
| Income before cumulative effect of change in accounting principle | $ 2.48 | $ 2.28 | $ 2.13 |
| Cumulative effect of change in accounting principle | - | - | (0.12) |
| Fully diluted earnings per common share | $ 2.48 | $ 2.28 | $ 2.01 |
| Cash dividends paid per common share | $ 1.30 | $ 1.15 | $ 1.11 |
| Weighted average number of common shares outstanding | | | |
| Basic | 77.3 | 66.3 | 63.1 |
| Fully diluted | 77.8 | 67.0 | 63.7 |

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 Income | Shares Held in Treasury and Trust | Total |
|---|---|---|---|---|---|---|---|
| Balance as of December 31, 2002 | 57.8 | $ 289 | $ 210 | $ 279 | $ (49) | $ (19) | $ 710 |
| Comprehensive income: | | | | | | | |
| Net income | - | - | - | 128 | - | - | 128 |
| Other comprehensive income (OCI) - gain resulting from unfunded pension obligation (net of tax of $6) | - | - | - | - | 8 | - | 8 |
| Unrealized gain from equity investment hedging activities (net of tax ) | - | - | - | - | 1 | - | 1 |
| Total comprehensive income | | | | | | | 137 |
| Dividends on common stock ($1.11 per share) | - | - | - | (70) | - | - | (70) |
| Issuance of common shares: | | | | | | | |
| Equity offering on February 14, 2003 | 6.7 | 32 | 105 | - | - | - | 137 |
| Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $2) | - | 1 | 11 | - | - | 19 | 31 |
| Balance as of December 31, 2003 | 64.5 | 322 | 326 | 337 | (40) | - | 945 |
| Comprehensive income: | | | | | | | |
| Net income | - | - | - | 153 | - | - | 153 |
| OCI - loss resulting from unfunded pension obligation (net of tax benefit of $7) | - | - | - | - | (11) | - | (11) |
| Unrealized gain from 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 benefit 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 benefit | - | - | - | - | (5) | - | (5) |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| of $3) | | | | | | | |
| Unrealized loss from hedging activities (net of tax benefit of $1) | - | - | - | - | (2) | - | (2) |
| Total comprehensive income | | | | | | | 186 |
| Dividends on common stock ($1.30 per share) | - | - | - | (100) | - | - | (100) |
| Issuance of common shares: | | | | | | | |
| Benefit, stock compensation, dividend reinvestment and stock purchase plans (net of tax benefit of $9) | 1.1 | 5 | 23 | - | - | - | 28 |
| Balance as of December 31, 2005 | 77.8 | $ 389 | $ 655 | $ 508 | $ (53) | $ - | $ 1,499 |

See Notes to Consolidated Financial Statements.

**AGL Resources Inc.**
**Statements of Consolidated Cash Flows**

| | Years ended December 31, | | |
|---|---|---|---|
| *In millions* | 2005 | 2004 | 2003 |
| **Cash flows from operating activities** | | | |
| Net income | $ 193 | $ 153 | $ 128 |
| Adjustments to reconcile net income to net cash flow provided by operating activities | | | |
| Depreciation and amortization | 133 | 99 | 91 |
| Minority interest | 22 | 18 | - |
| Change in risk management assets and liabilities | 27 | (32) | (1) |
| Deferred income taxes | 17 | 65 | 55 |
| Cumulative effect of change in accounting principle | - | - | 13 |
| Cash received from equity interests | - | - | 40 |
| Equity in earnings of unconsolidated subsidiaries | - | (2) | (47) |
| Gain on sale of Caroline Street campus | - | - | (16) |
| Other non cash adjustments | 12 | 11 | 10 |
| Changes in certain assets and liabilities | | | |
| Payables | 311 | 247 | 61 |
| Inventories | (211) | (28) | (91) |
| Receivables | (338) | (264) | (67) |
| Other - net | (88) | 20 | (54) |
| Net cash flow provided by operating activities | 78 | 287 | 122 |
| **Cash flows from investing activities** | | | |
| Expenditures for property, plant and equipment | (267) | (264) | (158) |
| 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) | - |
| Purchase of Dynegy Inc.'s 20% ownership interest in SouthStar Energy Services LLC | - | - | (20) |
| Cash received from sale of Caroline Street campus | - | - | 23 |
| Sale of US Propane LP | - | 31 | - |
| Other | 7 | 17 | 10 |
| Net cash flow used in investing activities | (194) | (422) | (145) |
| **Cash flows from financing activities** | | | |
| Net payments and borrowings of short-term debt | 188 | (480) | (82) |
| Sale of common stock | 28 | 36 | 12 |
| Distribution to minority interest | (19) | (14) | - |
| Dividends paid on common shares | (100) | (75) | (70) |
| Issuances of senior notes | - | 450 | 225 |
| Equity offering | - | 332 | 137 |
| Sale of treasury shares | - | - | 19 |
| Payments of medium-term notes | - | (82) | (207) |
| Other | - | - | (3) |
| Net cash flow provided by financing activities | 97 | 167 | 31 |
| Net (decrease) increase in cash and cash equivalents | (19) | 32 | 8 |
| Cash and cash equivalents at beginning of period | 49 | 17 | 9 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Cash and cash equivalents at end of period | $ | 30 | $ | 49 | $ | 17 |
| **Cash paid during the period for** | | | | | | |
| Interest (net of allowance for funds used during construction of $2 million for the years ended December 31, 2005, 2004 and 2003, respectively) | $ | 89 | $ | 50 | $ | 60 |
| Income taxes | | 89 | | 27 | | 23 |

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” or the “company” mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources). 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, 2005 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 reclassified certain amounts from prior periods to conform to the current-period presentation. We have eliminated any intercompany profits and transactions between segments in consolidation; however, we have not eliminated intercompany profits when such amounts are probable of recovery under the affiliates’ rate regulation process.

We use the equity method when we have a 20% to 50% voting interest to account for and report investments when we exercise significant influence but do not control and when we are not the primary beneficiary as defined by Financial Accounting Standards Board (FASB) Interpretation No. 46, “Consolidation of Variable Interest Entities” (FIN 46). FIN 46 requires the primary beneficiary of a variable interest entity’s activities to consolidate the variable interest entity. The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity’s activities.

We currently own a noncontrolling 70% financial interest in 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. Prior to 2004, we accounted for our 70% noncontrolling financial ownership interest in SouthStar using the equity method of accounting because SouthStar did not meet the definition of a variable interest entity under FIN 46. Under the equity method, we reported our ownership interest in SouthStar as an investment in our consolidated balance sheets, and we reported our share of SouthStar’s earnings based on our ownership percentage in our statements of consolidated income as a component of other income. However, because SouthStar’s results of operations and financial condition were material to our financial results in 2003, we present below the summarized amounts for 100% of SouthStar. These results are not comparable with our reported earnings or losses from SouthStar in 2003.

| *In millions* | | 2003 |
|---|---|---|
| Revenues | $ | 746 |
| Operating margin | | 124 |
| Operating income | | 63 |
| Net income from continuing operations | | 63 |

In December 2003, the FASB revised FIN 46 (FIN 46R) to add the following conditions for determining whether an entity is a variable interest entity:

.

the voting rights of some investors are not proportional to their obligations to absorb the expected losses of the entity, their rights to receive the expected residual returns of the entity, or both

- substantially all the entity's activities (for example, purchasing products and additional capital) either involve or are conducted on behalf of an investor that has disproportionately fewer voting rights

In 2004, we determined that SouthStar was a variable interest entity as defined in FIN 46R 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. 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).

As of January 1, 2004, we adopted FIN 46R and consolidated all SouthStar's accounts with our subsidiaries' accounts and eliminated any intercompany balances between segments. We recorded Piedmont's portion of SouthStar's earnings as a minority interest in our consolidated statements of income, and we recorded Piedmont's portion of SouthStar's capital as a minority interest in our consolidated balance sheet.

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 Corporation 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.

**Inventories**

For our regulated subsidiaries, we record natural gas stored underground at weighted average costs, except for gas stored by Atlanta Gas Light on behalf of SouthStar. For our nonregulated subsidiaries, primarily Sequent Energy Management, L.P. (Sequent), SouthStar and Pivotal Jefferson Island Storage & Hub, L.L.C. (Pivotal Jefferson Island), we account for natural gas inventory at the lower of weighted average cost or market. 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, we record 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, the marketing affiliate of Atlanta Gas Light — 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, 2005 and 2004 is indicated in the following table.

| *In millions* | 2005 | 2004 |
|---|---|---|
| Transmission & distribution | $ 3,867 | $ 3,731 |
| Storage | 209 | 206 |
| Other | 476 | 418 |

| | | |
|---|---|---|
| Construction work in progress | 239 | 260 |
| Total gross PP&E | 4,791 | 4,615 |
| Accumulated depreciation | (1,520) | (1,437) |
| Total net PP&E | $ 3,271 | $ 3,178 |

***Distribution Operations*** Property, plant and equipment expenditures consist of property and equipment that is in use, being held for future use and under construction. We report it at its original cost, which includes

- material and labor
- contractor costs
- construction overhead costs
- an allowance for funds used during construction which represents the estimated cost of funds used to finance the construction of major projects and are 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*** Property, plant and equipment 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.

**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 2.6% during 2005, 2.6% during 2004 and 2.7% during 2003. The composite, straight-line rate for Elizabethtown Gas, Florida City Gas and Elkton Gas was approximately 3.1% during 2005 and was 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.

**Allowance for Funds Used During Construction (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 has authorized a rate of 7.43%. The New Jersey Board of Public Utilities (NJBPU) has authorized a variable rate based on the FERC method of accounting for AFUDC. At December 31, 2005 the rate was 4.33%. The capital expenditures of our other regulated utilities do not qualify for AFUDC treatment.

**Goodwill**

We adopted Statement of Financial Accounting Standards (SFAS) No. 142, “Goodwill and Other Intangible Assets” (SFAS 142), effective October 1, 2001. Under SFAS 142, we no longer amortize goodwill. SFAS 142 further requires us to perform an initial goodwill impairment assessment in the year of adoption and annual impairment tests thereafter. We have included $422 million of goodwill in our consolidated balance sheets, of which $231 million is related to our acquisition of NUI Corporation (NUI) in November 2004 (see Note 2 for further details); $170 million is related to our acquisition of Virginia Natural Gas in 2000, a decrease of $6 million from last year due to a deferred income tax adjustment made in 2005; $14 million is related to our acquisition of Jefferson Island Storage & Hub, LLC in October 2004; and $7 million is related to our acquisition of Chattanooga Gas in 1988.

We annually assess goodwill for impairment as of our fiscal year end at a reporting unit level which generally equates to our operating segments as discussed in Note 14, and have not recognized any impairment charges for the years ended December 31, 2005, 2004 and 2003. 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, an impairment loss equal to the excess of the asset’s carrying value over its fair value is recorded. We conduct this assessment principally through a review of financial results, changes in state and federal legislation and regulation, and the periodic regulatory filings for our regulated utilities.

**Accumulated Deferred 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. 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. Investment tax credits of approximately $19 million previously deducted for income tax purposes for Atlanta Gas Light, Chattanooga Gas and Elizabethtown 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.

**Revenues**

***Distribution Operations*** We record revenues when services are provided to customers. Those revenues are based on rates approved by the regulatory state 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, 2005 and 2004 (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. 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 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.

***Wholesale Services*** Wholesale services' revenues are recorded when services are provided to customers. Intercompany 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 recorded as revenues in our statements of income.

Prior to 2003, in accordance with SFAS 133, we accounted for nonderivative energy and energy-related activities in accordance with Emerging Issues Task Force (EITF) Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 98-10). Under these methods, we recorded energy commodity contracts (including physical transactions and financial instruments) at fair value and reflected unrealized gains and/or losses in earnings in the period of change. Effective January 1, 2003, we adopted EITF 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), which rescinded the provisions of EITF 98-10 and reached two general conclusions:

- contracts that do not meet the definition of a derivative under SFAS 133 should not be marked to fair market value
- revenues should be shown in the statement of consolidated income net of costs associated with trading activities, whether or not the trades are physically settled

As a result of our adoption of EITF 02-03, we adjusted the carrying value of our nonderivative trading instruments (principally storage capacity contracts) to zero and now account for them using the accrual method of accounting. In addition, we adjusted the value of our natural gas inventories used in wholesale services to the lower of average cost or market (they were previously recorded at fair value). This resulted in the cumulative effect of a change in accounting principle in our statements of consolidated income of $13 million ($8 million net of taxes). We also began reporting our trading activity on a net basis (revenues net of associated costs). This reclassification had no impact on our previously reported net income or shareholders’ equity.

**Cost of Gas**

Excluding Atlanta Gas Light, we charge our utility customers for the natural gas they consume 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.

**Stock-based Compensation**

We have several stock-based employee compensation plans and account for these plans under the recognition and measurement principles of Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25), and related interpretations. For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options for those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. For our stock appreciation rights, we reflect stock-based employee compensation cost based on the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25. The following table illustrates the effect on our net income and earnings per share had we applied the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation" (SFAS 123).

| *In millions, except per share amounts* | 2005 | 2004 | 2003 |
|---|---|---|---|
| Net income, as reported | $ 193 | $ 153 | $ 128 |
| Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effect | (1) | (1) | (1) |
| Pro-forma net income | $ 192 | $ 152 | $ 127 |
| | | | |
| Earnings per share: | | | |
| Basic - as reported | $ 2.50 | $ 2.30 | $ 2.03 |
| Basic - pro-forma | $ 2.48 | $ 2.28 | $ 2.02 |
| | | | |
| Fully diluted - as reported | $ 2.48 | $ 2.28 | $ 2.01 |
| Fully diluted - pro-forma | $ 2.47 | $ 2.26 | $ 2.00 |

**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, 2005, 2004 and 2003.

| *In millions* | 2005 | 2004 | 2003 |
|---|---|---|---|
| Cash flow hedges: | | | |
| Net derivative unrealized gains (losses) arising during the period (net of $3, $3 and $1 in taxes) | $ 5 | $ 6 | $ (1) |
| Less reclassification of realized (gains) losses included in income (net of $4, $1 and $2 in taxes) | (7) | (2) | 2 |
| Unfunded pension obligation (net of $3, $7 and $6 in taxes) | (5) | (11) | 8 |
| Other (net of tax) | - | 1 | - |
| Total | $ (7) | $ (6) | $ 9 |

**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. Fully 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 fully 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* | 2005 | 2004 | 2003 |
|---|---|---|---|
| Denominator for basic earnings per share (1) | 77.3 | 66.3 | 63.1 |
| Assumed exercise of potential common shares | 0.5 | 0.7 | 0.6 |
| Denominator for fully diluted earnings per share | 77.8 | 67.0 | 63.7 |

(1) Daily weighted average shares outstanding.

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**Use of Accounting Estimates**

The preparation of our financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include our regulatory accounting, the allowance for doubtful accounts, allowance for contingencies, pipeline replacement program (PRP) accruals, environmental liability accruals, unbilled revenue recognition, pension and postretirement obligations, derivative and hedging activities, and purchase price allocations. Actual results could differ from those estimates.

**> Note 2**
**Acquisition of NUI**

On November 30, 2004, we acquired NUI for approximately $825 million, including the assumption of $709 million in debt. The acquisition significantly expands our existing natural gas utilities, storage and pipeline businesses. During 2005, we adjusted our purchase price allocation by $74 million for additional known items, including adjustments related to pension obligations; severance; lease obligations related to NUI's former corporate offices; environmental remediation liabilities; income tax liabilities; and asset sales. In connection with the acquisition, we incurred $25 million in employee-related restructuring charges. As of December 31, 2005, $5 million of these payments remained to be paid. Our purchase price allocation as of December 31, 2004 and 2005 and the goodwill adjustments are indicated in the following table.

| *In millions* | Dec. 31, 2004 | Adjust-ments | Dec. 31, 2005 |
|---|---|---|---|
| Purchase price | $ 825 | $ - | $ 825 |
| Current assets | 299 | (1) | 298 |
| Property, plant and equipment | 612 | (15) | 597 |
| Other long-term assets | 117 | (21) | 96 |
| Goodwill | 157 | 74 | 231 |
| Current liabilities excluding debt | (108) | (4) | (112) |
| Short-term debt and capital leases | (502) | - | (502) |
| Long-term debt and capital leases | (207) | - | (207) |
| Other long-term liabilities | (143) | (31) | (174) |
| Equity | 225 | 2 | 227 |

We believe the acquisition resulted in the recognition of goodwill primarily because of the strength of NUI's underlying assets and the synergies and opportunities in the regulated utilities.

The table below reflects the unaudited pro forma results of AGL Resources and NUI for the years ended December 31, 2004 and 2003 as if the acquisition and related financing had taken place on January 1. The pro-forma results are not necessarily indicative of the results that would have occurred if the acquisition had been in effect for the periods presented. In addition, the pro-forma results are not intended to be a projection of future results and do not reflect any synergies that might be achieved from combining the operations or eliminating significant expenses that NUI incurred in its last year of operations. Our results of operations for 2004 include one month of the acquired operations of NUI.

| *In millions, except per share amounts* | 2004 | 2003 |
|---|---|---|
| Operating revenue | $ 2,343 | $ 1,630 |
| Income before cumulative effect of change in accounting principle | 105 | 88 |
| Net income | 105 | 74 |
| Net income per fully diluted share | 1.44 | 1.05 |

**Sale of Saltville** In August 2005, we sold our 50% interest in Saltville and associated subsidiaries (Virginia Gas Pipeline and Virginia Gas Storage) to a subsidiary of Duke Energy Corporation, the other 50% partner in the Saltville joint venture. We acquired these assets as part of our purchase of NUI. We received $66 million in cash at closing, which included $4 million in working capital adjustments, and used the proceeds to repay debt and for other general corporate purposes. The transaction was reflected as a decrease of $4 million in goodwill associated with the NUI acquisition.

**Sale of Other NUI Assets** In 2005, we sold an appliance business in Florida and Virginia Gas Distribution Company for proceeds totaling $7 million, which approximated their amounts on our consolidated balance sheets and have been recorded as adjustments to goodwill.

**> Note 3**
**Recent Accounting Pronouncements**

**SFAS 123(R)** In December 2004, the FASB issued SFAS No 123(R), "Accounting for Stock Based Compensation" (SFAS 123R). SFAS 123R revises the guidance in SFAS 123 and supersedes APB 25 and its related implementation guidance. SFAS 123R focuses primarily on the accounting for share-based payments to employees in exchange for services, and it requires a public entity to measure and recognize compensation cost for these payments. Our share-based payments are typically in the form of stock option and performance unit awards. The primary change in accounting under SFAS 123R is related to the requirement to recognize compensation cost for stock option awards that was not recognized under APB 25. SFAS 123R requires compensation cost to be measured based on the fair value of the equity or liability instruments issued. For stock option awards, fair value would be estimated using an option pricing model such as the Black-Scholes model.

SFAS 123R is effective for equity compensation expense in fiscal years beginning after December 15, 2005, and we will adopt it prospectively on January 1, 2006. We have assessed the impact SFAS 123R will have on our consolidated financial statements, and we believe the pro-forma effects on our earnings of recognizing compensation expense related to our stock option awards, contained in Note 1, serves as a reasonable proxy for the impact of this statement (approximately $1 million net of income taxes for 2006 and 2007 based on unvested stock options as of December 31, 2005).

**FIN 47** In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143" (FIN 47). Asset retirement obligations (AROs) are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal operation of a long-lived asset, except for certain obligations of lessees. FIN 47 clarifies that liabilities associated with asset retirement obligations whose timing or settlement method are conditional on future events should be recorded at fair value as soon as fair value is reasonably estimable. FIN 47 also provides guidance on the information required to reasonably estimate the fair value of the liability. FIN 47 is intended to result in

- more consistent recognition of liabilities relating to AROs among companies
- more information about expected future cash outflows associated with those obligations stemming from the retirement of the asset(s)
- more information about investments in long-lived assets because additional asset retirement costs will be recognized by increasing the carrying amounts of the assets identified to be retired

FIN 47 is effective for fiscal years ending after December 15, 2005. We adopted the provisions of FIN 47 during the fourth quarter of 2005. The impact of adoption was not material.

**> Note 4**
**Risk Management**

Our risk management activities are monitored by our Risk Management Committee (RMC). The RMC consists 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 risks:

- forward contracts
- futures contracts
- options contracts
- financial swaps
- storage and transportation capacity transactions

**Interest Rate Swaps**

To maintain an effective capital structure, it is our policy to borrow funds using a mix of fixed-rate and variable-rate debt. We have entered into interest rate swap agreements through our wholly owned subsidiary, AGL Capital Corporation (AGL Capital), 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 as prescribed by SFAS 133, which allows us to designate derivatives that hedge exposure to changes in the fair value of a recognized asset or liability. 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.

We adjust the carrying value of each interest rate swap to its fair value at the end of each period, with an offsetting and equal adjustment to the carrying value of the debt securities whose fair value is being hedged. Consequently, our earnings are not affected negatively or positively by changes in the fair value of the interest swaps.

As of December 31, 2005, 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, 2005 was 7.2%.

At the beginning of 2005, we had $75 million of outstanding interest rate swap agreements associated with our Note Payable at AGL Capital Trust II. On September 7, 2005, we terminated these interest rate swap agreements. We received a payment of $1 million related to this termination, which included accrued interest and the fair value of these interest rate swap agreements at the termination date.

In September 2005, we also executed five treasury-lock agreements totaling $125 million to hedge the interest rate risk associated with an anticipated 2006 financing. The agreements will result in a 4.11% interest rate on the 10-year United States Treasury bond against which we will be measured in issuing our own debt securities and the agreements were designated as cash flow hedges against the future interest payments on the anticipated financing. The fair value of this agreement was $3 million at December 31, 2005, with the increase in the fair value included as a credit to OCI.

**Commodity-related Derivative Instruments**

***Elizabethtown Gas*** A program mandated by the NJBPU requires Elizabethtown Gas to utilize certain derivatives to hedge the impact of market fluctuations in natural gas prices. Pursuant to SFAS 133, such derivative products 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, 2005, Elizabethtown Gas had entered into New York Mercantile Exchange (NYMEX) futures contracts to purchase approximately 8.3 billion cubic feet (Bcf) of natural gas and the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $17 million and a liability of $21 million. Approximately 81% of these contracts have a duration of one year or less, and none of these contracts extends beyond October 2007.

***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, are recorded at fair value and are 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 basis 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 net income, even though the economic margin is essentially unchanged from the date the transactions were consummated.

At December 31, 2005, Sequent's commodity-related derivative financial instruments represented purchases (long) of 411 Bcf and sales (short) of 464 Bcf, with approximately 94% of these scheduled to mature in less than two years and the remaining 6% in three to nine years. At December 31, 2005, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $80 million and a liability of $97 million. Excluding the cumulative effect of a change in accounting principle in 2003, our unrealized loss was $30 million in 2005, and we had unrealized gains of $22 million in 2004 and $1 million in 2003.

***SouthStar*** The commodity-related derivative financial instruments (futures, options and swaps) used by SouthStar 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, 2005, the fair values of these derivatives were reflected in our consolidated financial statements as an asset of $7 million and a liability of $4 million. The maximum maturity of open positions is less than one year and represents purchases and sales of 3.2 Bcf.

SouthStar also enters 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's member firms. For over-the-counter transactions, SouthStar utilizes master netting arrangements to reduce overall credit risk. As of December 31, 2005, SouthStar's maximum exposure to any single over-the-counter counterparty was $2 million.

**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 10 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. A customer that does not have an external rating is assigned an internal rating based on Sequent's analysis of the strength of its financial ratios. At December 31, 2005, Sequent's top 20 customers represented approximately 52% of the total credit exposure of $554 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, 2005.

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

Sequent has established credit policies to determine and monitor the creditworthiness of counterparties, including requirements for posting of collateral or other credit security, as well as the quality of pledged collateral. Collateral or credit security is most often in the form of cash or letters of credit from an investment grade financial institution, but may also include cash or U.S. Government Securities held by a trustee. When Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with which it conducts significant transactions.

**> Note 5**
**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 and unrecovered environmental remediation costs (ERC), are summarized in the table below.

| | December 31, | |
|---|---|---|
| *In millions* | 2005 | 2004 |
| **Regulatory assets** | | |
| Unrecovered PRP costs | $ 303 | $ 361 |
| Unrecovered ERC | 196 | 200 |
| Unrealized loss on hedging derivatives | 17 | 6 |
| Unrecovered postretirement benefit costs | 14 | 14 |
| Unrecovered seasonal rates | 11 | 11 |
| Unrecovered PGA | 8 | 2 |
| Regulatory tax asset | 1 | 2 |
| Other | 9 | 20 |
| Total regulatory assets | $ 559 | $ 616 |
| **Regulatory liabilities** | | |
| Accumulated removal costs | $ 94 | $ 94 |
| Unrealized gain on hedging derivatives | 21 | 6 |
| Unamortized investment tax credit | 19 | 20 |
| Deferred PGA | 36 | 60 |
| Regulatory tax liability | 15 | 14 |
| Other | 6 | 12 |
| Total regulatory liabilities | 191 | 206 |
| **Associated liabilities** | | |
| PRP costs | 265 | 327 |
| ERC | 97 | 90 |
| Total associated liabilities | 362 | 417 |
| Total regulatory and associated liabilities | $ 553 | $ 623 |

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, which would be classified as an extraordinary item. However, 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 deferred PGA, which are recovered through specific rate riders. 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.

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.

**Pipeline Replacement Program**

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, 2005 marked the beginning of the eighth 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 SFV 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. The amendment requires an evaluation by Atlanta Gas Light and the

Georgia Commission staff of 22 miles of 24 inch pipe in Atlanta by December 2010 to determine if such pipe requires replacement. If replacement of this pipe is required, the pipe must be replaced by December 2013. The additional cost to replace this pipe is projected to be approximately $37 million.

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 PRP rate that Atlanta Gas Light will charge a fixed rate 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 $276 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

- $26 million in 2005
- $28 million in 2004
- $15 million in 2003

As of December 31, 2005, Atlanta Gas Light had recorded a current liability of $30 million, representing expected program expenditures for the next 12 months and a long-term liability of $235 million, representing expected program expenditures from 2007 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.

**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 engineering estimate projects costs of $12 million to complete site remediation in Georgia and Florida, excluding monitoring. This is a reduction of $24 million from last year's estimate, resulting primarily from program expenditures. During the same 12-month period Atlanta Gas Light realized changes in its future cost estimates totaling $6 million related to

- an increase in the contract value at its Augusta, Georgia site for treatment of two areas and a reduction of $2 million in groundwater costs related to active treatment system operations
- a decrease at its Savannah, Georgia site of $4 million for groundwater treatment costs and contractual liability
- a decrease of $1 million at its Griffin, Georgia site for groundwater treatment costs
- an increase of $1 million for additional remediation and investigative costs at its various sites in Georgia and Florida

The current estimate for the remaining cost of future actions at these former operating sites is $15 million, which may change depending on whether future measures for groundwater will be required. Atlanta Gas Light estimates certain other costs related to administering the remediation program, including administrative costs, to be $4 million.

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 with respect to which it cannot reasonably estimate an amount. As of December 31, 2005, the remediation expenditures expected to be incurred over the next 12 months are reflected as a current liability of $10 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 $29 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

- $28 million in 2005
- $25 million in 2004
- $23 million in 2003

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 2005, 2004 or 2003. The third way to recover costs is from the receipt of net profits from the sale of remediated property. There were no sales of property during 2005.

***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 $57 million to $104 million. As of December 31, 2005, no value within this range was a better estimate than any other value, so we have recorded a liability equal to the low end of that range, or $57 million.

Prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through a remediation adjustment clause. As a result, Elizabethtown Gas has recorded a regulatory asset of approximately $63 million, inclusive of interest, as of December 31, 2005, reflecting the future recovery of both incurred costs and accrued carrying charges. 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.

***Sites in North Carolina*** We also 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. We currently have only partial information regarding environmental impacts at the Elizabeth City site, and therefore we can make quantitative cost estimates only for limited components of a site cleanup. However, experience at other similar sites suggests that costs for remediation of this site will likely range from $10 million to $17 million. As of December 31, 2005, 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 6**
**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 NUI Corporation Retirement Plan (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 is a qualified noncontributory defined benefit retirement plan that covers substantially all of NUI's employees 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 now administer 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 will become 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 option is not permitted under the AGL Retirement Plan. The following tables present details about our pension plans.

| | AGL Retirement Plan | | NUI Retirement Plan | |
|---|---|---|---|---|
| | Dec, 31, 2005 | Dec. 31, 2004 | Dec. 31, 2005 | Dec. 31, 2004 |
| **Change in benefit obligation** | | | | |
| Benefit obligation at beginning of year | $ 340 | $ 314 | $ 144 | $ 144 |
| Service cost | 6 | 5 | 4 | - |
| Interest cost | 19 | 19 | 8 | 1 |
| Plan amendments | - | - | (15) | - |
| Actuarial loss (gain) | 14 | 21 | (4) | - |
| Benefits paid | (20) | (19) | (32) | (1) |
| Benefit obligation at end of year | $ 359 | $ 340 | $ 105 | $ 144 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | $ 279 | $ 259 | $ 111 | $ 108 |
| Actual return on plan assets | 21 | 26 | 6 | 4 |
| Employer contribution | 6 | 13 | - | - |
| Benefits paid | (20) | (19) | (32) | (1) |
| Fair value of plan assets at end of year | $ 286 | $ 279 | $ 85 | $ 111 |
| **Funded status** | | | | |
| Plan assets less than benefit obligation at end of year | $ (73) | $ (61) | $ (20) | $ (33) |
| Unrecognized net loss | 119 | 108 | 4 | - |
| Unrecognized prior service benefit | (10) | (11) | (15) | (3) |
| Accrued (prepaid) pension cost (1) | $ 36 | $ 36 | $ (31) | $ (36) |
| **Amounts recognized in the statement of financial position consist of** | | | | |
| Prepaid benefit cost | $ 42 | $ 43 | $ - | $ - |
| Accrued benefit liability | (7) | (7) | (31) | (36) |
| Accumulated OCI | (92) | (84) | - | - |
| Net amount recognized at year end | $ (57) | $ (48) | $ (31) | $ (36) |

(1) 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. We recorded the associated $9 million reduction in our benefit obligation as a reduction to goodwill.

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 | |
|---|---|---|---|---|
| | Dec. 31, 2005 | Dec. 31, 2004 | Dec. 31, 2005 | Dec. 31, 2004 |
| Projected benefit obligation | $ 359 | $ 340 | $ 105 | $ 144 |
| ABO | 343 | 327 | 105 | 118 |
| Fair value of plan assets | 286 | 279 | 85 | 111 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Increase in minimum liability included in OCI | | 8 | | 18 | | - | - |
| **Components of net periodic benefit cost** | | | | | | | |
| Service cost | $ | 6 | $ | 5 | $ | 4 | $ - |
| Interest cost | | 19 | | 19 | | 8 | 1 |
| Expected return on plan assets | | (24) | | (23) | | (9) | (1) |
| Net amortization | | (1) | | (1) | | - | - |
| Recognized actuarial loss | | 7 | | 5 | | - | - |
| Net annual pension cost | $ | 7 | $ | 5 | $ | 3 | $ - |

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The following table set forth the assumed weighted average discount rates and rates of compensation increase used to determine benefit obligations at the balance sheet dates.

| | AGL and NUI Retirement Plans | |
|---|---|---|
| | Dec. 31, 2005 | Dec. 31, 2004 |
| Discount rate | 5.5% | 5.8% |
| 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.

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 | |
|---|---|---|
| | Dec. 31, 2005 | Dec. 31, 2004 |
| Discount rate | 5.8% | 6.3% |
| Expected return on plan assets | 8.8% | 8.8% |
| Rate of compensation increase | 4.0% | 4.0% |

| | NUI Retirement Plan | |
|---|---|---|
| | Dec. 31, 2005 | Dec. 31, 2004 |
| Discount rate | 5.8% | 5.8% |
| Expected return on plan assets | 8.5% | 8.5% |
| Rate of compensation increase | 4.0% | 4.0% |

We consider a number of factors in determining and selecting our assumptions for the discount rate at December 31. We consider certain market indices, including the Moody’s Corporate AA long-term bond rate of 5.41% and the Citigroup Pension Liability rate of 5.51%, at December 31, 2005. We further use these market indices as a comparison to a single equivalent discount rate derived with the assistance of our actuarial advisors. The single equivalent discount rate is based on a yield-to-maturity regression analysis of a portfolio of corporate bonds rated AA by Moody’s and that have cash outflows consistent with payouts from our retirement plans. This analysis as of December 31, 2005 produced a single equivalent discount rate of 5.63%. Consequently, we selected a discount rate of 5.5% as of December 31, 2005, following our review of these various factors.

Our actual retirement plans’ weighted average asset allocations at December 31, 2005 and 2004 and our target asset allocation ranges are as follows.

| | Target Range Allocation of Assets | AGL Retirement Plan | |
|---|---|---|---|
| | | 2005 | 2004 |
| Equity | 40%-85% | 66% | 71% |
| Fixed income | 25%-50% | 25% | 25% |
| Real estate and other | 0%-10% | 8% | 3% |

| | | | |
|---|---|---|---|
| Cash | 0%-10% | 1% | 1% |

| | Target Range Allocation of Assets | NUI Retirement Plan 2005 | 2004 |
|---|---|---|---|
| Equity | 40%-85% | 88% | 72% |
| Fixed income | 25%-50% | 12% | 28% |
| Real estate and other | 0%-10% | - | - |
| Cash | 0%-10% | - | - |

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 table above, but the Committee can vary allocations between various classes and/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. We do not expect to make any contribution to the pension plans in 2006.

**Postretirement Benefits**

We sponsor 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 provides 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 is 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 pensions 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. Beginning in 2006, eligible participants in the NUI Postretirement Plan will become eligible to participate in the AGL Postretirement Plan.

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 $14 million as of December 31, 2005 and $14 million as of December 31, 2004. In addition, we recorded a regulatory liability of $3 million as of December 31, 2005 and $2 million as of December 31, 2004 for our expected expenses under the AGL Postretirement Plan.

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.

The AGL Postretirement Plan's accumulated postretirement benefit obligation decreased by approximately $24 million and net annual cost decreased by $2 million due to the elimination of prescription drug coverage for Medicare-eligible retirees. The 2004 net periodic postretirement benefit cost reflects both the plan amendment to remove prescription drug coverage under the AGL Postretirement Plan, described above, and the federal subsidy for NUI grandfathered retirees. The following tables present details about our postretirement benefits.

| *In millions* | AGL Postretirement Plan Dec. 31, 2005 | AGL Postretirement Plan Dec. 31, 2004 | NUI Postretirement Plan Dec, 31, 2005 | NUI Postretirement Plan Dec. 31, 2004 |
|---|---|---|---|---|
| **Change in benefit obligation** | | | | |
| Benefit obligation at beginning of year | $ 98 | $ 134 | $ 23 | $ 23 |
| Service cost | 1 | 1 | - | - |
| Interest cost | 5 | 7 | 1 | - |
| Plan amendments | - | (24) | (7) | - |
| Actuarial (gain) loss | (6) | (12) | 3 | - |
| Benefits paid | (9) | (8) | (2) | - |
| Benefit obligation at end of year | $ 89 | $ 98 | $ 18 | $ 23 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | $ 49 | $ 44 | $ 9 | $ 9 |
| Actual return on plan assets | 4 | 5 | - | - |
| Employer contribution | 6 | 8 | 2 | - |
| Benefits paid | (9) | (8) | (2) | - |
| Fair value of plan assets at end of year | $ 50 | $ 49 | $ 9 | $ 9 |
| **Funded status** | | | | |
| ABO in excess of plan assets | $ (39) | $ (49) | $ (9) | $ (14) |
| Unrecognized loss | 22 | 30 | 2 | - |
| Unrecognized transition amount | 1 | 1 | - | - |
| Unrecognized prior service benefit | (23) | (26) | (6) | - |
| Accrued benefit cost | $ (39) | $ (44) | $ (13) | $ (14) |
| **Amounts recognized in the statement of financial position consist of** | | | | |
| Prepaid benefit cost | $ - | $ - | $ - | $ - |
| Accrued benefit liability | (39) | (44) | (13) | (14) |
| Accumulated OCI | - | - | - | - |
| Net amount recognized at year end | $ (39) | $ (44) | $ (13) | $ (14) |

The following table presents details on the components of our net periodic benefit cost at the balance sheet dates for the AGL Postretirement Plan. Amounts for the NUI Postretirement Plan were not material in 2004.

| *In millions* | AGL Postretirement Plan 2005 | AGL Postretirement Plan 2004 |
|---|---|---|
| Service cost | $ 1 | $ 1 |
| Interest cost | 5 | 7 |
| Expected return on plan assets | (4) | (3) |
| Amortization of prior service cost | (3) | (2) |
| Recognized actuarial loss | 1 | 1 |
| Net periodic postretirement benefit cost | $ - | $ 4 |

NUI
Postretirement
Plan

| *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 | $ | - |

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 | |
|---|---|---|
| | 2005 | 2004 |
| Discount rate - benefit obligation | 5.5% | 5.8% |
| Discount rate - net periodic benefit cost | 5.8% | 6.3% |
| Expected return on plan assets | 8.8% | 8.8% |
| Rate of compensation increase | 4.0% | 4.0% |

| | NUI Postretirement Plan | |
|---|---|---|
| | 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 | - | - |

For information on the discount rate assumptions used for our postretirement plans, see discussion contained in Note 6 under 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, | 2005 | 2004 | 2005 | 2004 |
| Health care costs trend assumed for next year | 2.5% | 11.3% | 2.5% | 11.3% |
| 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 | 2006 | N/A | 2006 |

| | NUI Postretirement Plan | |
|---|---|---|
| Assumed Health Care Cost Trend Rates at December 31, | 2005 | 2004 |
| Health care costs trend assumed for next year | 2.5% | 9.0% |
| Rate to which the cost trend rate gradually declines | 2.5% | 5.0% |
| Year that the rate reaches the ultimate trend rate | N/A | 2008 |

Effective January 2006, our health care trend rates for both the AGL Postretirement and NUI Postretirement Plans have been 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 | (3) |

| | NUI Postretirement Plan One-Percentage-Point | |
|---|---|---|
| *In millions* | Increase | Decrease |
| Effect on total of service and interest cost | $ - | $ - |
| Effect on accumulated postretirement benefit obligation | 2 | (1) |

The following table presents expected benefit payments covering the periods 2006 through 2015 for our qualified pension plans, unqualified pension plans, and postretirement health care plans. There will be benefit payments under these plans beyond 2015.

| For the year ended Dec. 31, *(in millions)* | AGL Retirement Plan | AGL Postretirement Plan |
|---|---|---|
| 2006 | $ 19 | $ 6 |
| 2007 | 19 | 6 |
| 2008 | 19 | 6 |
| 2009 | 19 | 6 |
| 2010 | 19 | 6 |
| 2011-2015 | 105 | 31 |

| For the year ended Dec. 31, *(in millions)* | NUI Retirement Plan | NUI Postretirement Plan |
|---|---|---|
| 2006 | $ 7 | $ 1 |
| 2007 | 7 | 1 |
| 2008 | 7 | 1 |
| 2009 | 7 | 1 |
| 2010 | 8 | 1 |
| 2011-2015 | 45 | 5 |

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 2005 and 2004 and our target asset allocation ranges are as follows.

| | Target Asset Allocation Ranges | 2005 | 2004 |
|---|---|---|---|
| Equity | 40%-85% | 52% | 67% |
| Fixed income | 25%-50% | 46% | 32% |
| Real estate and other | 0%-10% | 1% | -% |
| Cash | 0%-10% | 1% | 1% |

**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:

- $5 million in 2005
- $5 million in 2004
- $4 million in 2003

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.

Effective December 1, 2004, all NUI employees participating in NUI's qualified defined contribution benefit plan were eligible to participate in the RSP, and those who were participants in NUI's nonqualified defined contribution plan became eligible to participate in the NSP.

**> Note 7**
**Stock-based and Other Incentive Compensation Plans**

**Employee Stock-based Compensation Plans and Agreements**

We currently sponsor the following stock-based compensation plans

- The Long-Term Incentive Plan (1999)(LTIP) provides for grants of incentive and nonqualified stock options, performance units and shares of restricted stocks to key employees. The LTIP authorizes the issuance of up to 9.5 million shares of our common stock.
- A predecessor plan, the Long-Term Stock Incentive Plan (LTSIP), provides for grants of incentive and nonqualified stock options, shares of restricted stocks 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 grants 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.
    - Stock Appreciation Rights (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 were outstanding as of December 31, 2005.
- The 1996 Non-Employee Directors Equity Compensation Plan (Directors Plan) originally provided for the grant of nonqualified stock options and shares of restricted stock to nonemployee directors as payment of their annual retainer. In December 2002, the Directors Plan was amended to eliminate the granting of stock options. As a result, the Directors Plan now provides solely for the issuance of our common stock. The Directors Plan authorizes the issuance of up to 200,000 shares of our common stock.
- 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.

**Incentive and Nonqualified Stock Options**

We grant incentive and nonqualified stock options at the fair market value on the date of the grant. The vesting of incentive options is subject to a statutory limitation of $100,000 per year under Section 422A of the Internal Revenue

Code. Otherwise, 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.

The following table summarizes activity related to grants of stock options for key employees and nonemployee directors.

| | Number of Options | | Weighted Average Exercise Price |
|---|---|---|---|
| Outstanding-Dec.31, 2002 | 3,633,957 | $ | 20.55 |
| Granted | 939,262 | | 26.76 |
| Exercised | (863,112) | | 20.08 |
| Forfeited | (199,137) | | 22.00 |
| Outstanding-Dec.31, 2003 | 3,510,970 | $ | 22.25 |
| Granted | 103,900 | | 29.72 |
| Exercised | (1,050,053) | | 20.90 |
| Forfeited | (390,745) | | 22.44 |
| Outstanding-Dec.31, 2004 | 2,174,072 | $ | 23.23 |
| Granted | 1,014,121 | | 33.80 |
| Exercised | (846,465) | | 22.60 |
| Forfeited | (120,483) | | 32.38 |
| Outstanding-Dec. 31, 2005 | 2,221,245 | $ | 27.79 |

Information about outstanding and exercisable options as of December 31, 2005 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 |
| $13.75 to $17.49 | 2,199 | 4.0 | $ | 16.99 | 2,199 | $ | 16.99 |
| $17.50 to $19.99 | 56,295 | 2.1 | $ | 18.82 | 56,295 | $ | 18.82 |
| $20.00 to $24.10 | 714,623 | 4.3 | $ | 21.10 | 714,623 | $ | 21.10 |
| $24.11 to $30.00 | 487,255 | 7.3 | $ | 27.00 | 454,840 | $ | 26.97 |
| $30.01 to $34.00 | 792,052 | 8.8 | $ | 33.09 | 46,453 | $ | 31.00 |
| $34.01 to $39.50 | 168,821 | 7.6 | $ | 36.65 | 1,279 | $ | 35.81 |
| **Outstanding - Dec. 31, 2005** | **2,221,245** | **6.8** | **$** | **27.79** | **1,275,689** | **$** | **23.46** |

Summarized below are outstanding options that are fully exercisable.

| Exercisable at: | Number of Options | | Weighted Average Exercise Price |
|---|---|---|---|
| December 31, 2003 | 2,154,877 | $ | 20.47 |
| December 31, 2004 | 1,658,260 | $ | 22.04 |
| December 31, 2005 | 1,275,689 | $ | 23.46 |

Our stock-based employee compensation plans are accounted for under the recognition and measurement principles of APB 25 and related interpretations. For our stock option plans, we generally do not reflect stock-based employee compensation cost in net income, as options for those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. For our SARs, we reflect stock-based employee compensation cost based on the fair value of our common stock at the balance sheet date since these awards constitute a variable plan under APB 25.

In accordance with the fair value method of determining compensation expense, we used the Black-Scholes pricing model and the estimates listed below for the years ended December 31, 2005, 2004 and 2003.

| | | 2005 | | 2004 | | 2003 |
|---|---|---|---|---|---|---|
| Expected life (years) | | 7 | | 7 | | 7 |
| Interest rate | | 4.0% | | 3.7% | | 3.8% |
| Volatility | | 17.3% | | 16.9% | | 19.2% |
| Dividend yield | | 3.7% | | 3.9% | | 4.2% |
| Fair value of options granted | $ | 4.70 | $ | 3.72 | $ | 3.75 |

The compensation costs that have been charged against income for performance units, restricted stock and other stock-based awards were $5 million in 2005, $7 million in 2004 and $8 million in 2003.

**Stock Appreciation Rights**

We have granted SARs, which are payable in cash, at fair market value on the date of grant. SARs generally become fully exercisable not earlier than 12 months after the date of grant and generally expire six years after that date. Participants realize value from SAR grants only to the extent that the fair market value of our common stock on the date of exercise of the SAR exceeds the fair market value of the common stock on the date of the grant.

We recognize the intrinsic value of the SARs as compensation expense over the vesting period. Compensation expense for 2005, 2004 and 2003 was immaterial. The following table summarizes activity related to grants of SARs.

| | Number of SARs | Weighted Average Exercise Price | |
|---|---|---|---|
| Outstanding as of Dec.31, 2002 | 141,253 | $ | 23.50 |
| Issued | 45,790 | | 24.30 |
| Exercised | (17,718) | | 23.50 |
| Forfeited | (9,368) | | 23.99 |
| Outstanding as of Dec.31, 2003 | 159,957 | | 23.70 |
| Issued | - | | - |
| Exercised | (60,262) | | 23.70 |
| Forfeited | (72,832) | | 23.50 |
| Outstanding as of Dec.31, 2004 | 26,863 | | 24.24 |
| Issued | - | | - |
| Exercised | - | | - |
| Forfeited | - | | - |
| Outstanding as of Dec. 31, 2005 | 26,863 | | 24.24 |

**Performance Units**

In general, a performance unit is an award of the right to receive (i) an equal number of shares of company 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. In January 2005, we granted restricted stock units and performance cash units to a select group of officers as described below.

***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 January 2005, we granted to a select group of officers a total of 86,800 restricted stock units (the 2005 restricted stock units) under the LTIP, of which 77,300 of these units were outstanding as of December 31, 2005. The 2005 restricted stock units had a 12-month performance measurement period related to management's success in integrating its acquisitions and generating improvement in earnings from these acquired businesses. The performance measure was achieved during 2005. On January 3, 2006, the 2005 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.

In January 2005, we granted performance cash units to a select group of officers under the LTIP. The performance cash units represent a maximum aggregate payout of $3 million. The performance cash units have a performance measurement period that ranges from 12 to 36 months and a performance measure that relates to our internal measure of total shareholder return. As of December 31, 2005, based on our anticipated performance, we had recorded a liability of $2 million for these performance cash units. In addition, in 2005, we granted performance cash units to select executives that were intended to recognize the executive's promotion into key senior leadership roles and retain the executives.

At the end of the performance measurement period for the 12-month performance cash units (December 31, 2005), the performance measure was achieved and in January 2006 an aggregate of $743,680 was paid.

***2002 Performance Unit Awards*** In February 2002, we granted to a select group of officers a total of 1.5 million performance units with a performance measurement period that ended December 31, 2004. The amount actually earned was based on the highest average closing price of our common stock over any 10 consecutive trading days during the performance measurement period and could range from a minimum of 10% to 100% of the units granted. During a portion of the performance measurement period, these units were eligible for dividend credits based on vested performance units. Of the 1.5 million units that were granted, 1 million units were eligible for vesting at December 31, 2004. Upon vesting, at the election of the participant the performance units were payable in shares of our common stock, or up to 50% in cash.

These units were paid out as follows:

· $2.6