AGL RESOURCES INC
Form 8-K
January 28, 2005

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

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported): January 28, 2005

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

Georgia	**1-14174**	**58-2210952**
(State or other jurisdiction of incorporation)	(Commission File No.)	(I.R.S. Employer Identification No.)

Ten Peachtree Place NE, Atlanta, Georgia 30309
(Address and zip code of principal executive offices)

404-584-4000
(Registrant's telephone number, including area code)

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

[ ] Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

[ ] Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

[ ] Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

[ ] Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 2.02 Results of Operations and Financial Condition

On January 28, 2005, AGL Resources Inc. announced its financial results for the three and twelve months ended December 31, 2004 and certain other information. A copy of AGL Resources press release announcing such financial results and other information is attached as Exhibit 99.1 hereto and incorporated by reference herein.

The information in the preceding paragraph, as well as Exhibit 99.1 referenced therein, shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933.

Item 7.01 Regulation FD Disclosure

On January 28, 2005 at 9:00 a.m. AGL Resources plans to hold a fourth quarter 2004 earnings conference call. The company is filing this Form 8-K to provide selected discussion of financial results, liquidity and market risks as of December 31, 2004.

Cautionary Statement Regarding Forward-looking Information

Certain expectations and projections regarding our future performance referenced 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 may also make verbal statements to analysts, investors, regulators, the media and others that are forward-looking.

Forward-looking statements involve matters that are not historical facts, such as projections of our financial performance, management s goals and strategies for our business and assumptions regarding the foregoing. Because these statements involve anticipated events or conditions, forward-looking statements often include words such as anticipate, assume, can, could, estimate, expect, forecast, indicate, intend, may, plan, predict, target, will , would or similar expressions. For example, in this report, we have forward-looking statements regarding our expectations for:

- Revenue growth
- Operating income growth
- Cash flows from operations
- Operating expense growth
- Capital expenditures
- Our business strategies and goals
- Our potential for growth and profitability
- Our ability to integrate our recent and future acquisitions
- Trends in our business and industries, and
- Developments in accounting standards

Do not unduly rely on forward-looking statements. They represent our expectations about the future and are not guarantees. Our expectations 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. We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in Risk Factors, among others, could cause our business, results of operations or financial condition in 2005 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors 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 changes.

Overview

Nature of Our Business

We are an energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve more than 2.2 million end-use customers, making us the largest distributor of natural gas in the eastern United States based on number of customers. We are also involved in various related businesses, including retail natural gas marketing to end-use customers in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for other non-affiliated companies; natural gas storage arbitrage and related activities; operation of high deliverability underground natural gas storage; and construction and operation of telecommunications conduit and fiber infrastructure within select metropolitan areas. We manage these businesses through three operating segments - distribution operations, wholesale services and energy investments - and a non-operating corporate segment.

The distribution operations segment is the largest component of our business and is comprehensively regulated by regulatory agencies in six states. These agencies approve rates that are 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 franchise, the earnings of our regulated utilities are weather-sensitive to varying degrees. Although various regulatory mechanisms provide a reasonable opportunity to recover our fixed costs regardless of volumes sold, the effect of weather manifests itself in terms of higher earnings during periods of colder weather and lower earnings with warmer weather. Our Georgia retail marketing business, SouthStar Energy Services LLC (SouthStar), also is weather sensitive, and uses a variety of hedging strategies to mitigate potential weather impacts. All of our utilities and SouthStar faces competition in the residential and commercial customer markets based on customer preferences for natural gas compared with other energy products and the price of those products relative to that of natural gas.

We derived approximately 96 percent of our earnings before interest and taxes (EBIT) during the year ended December 31, 2004 from our regulated natural gas distribution business and from sales of natural gas to end-use customers in Georgia by SouthStar (which is part of our energy investments segment). This statistic is significant because it represents the portion of our earnings that results directly 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 and the items it excludes from operating income and net income, see Results of Operation - AGL Resources.

The remaining 4 percent of our EBIT was derived principally from businesses that are complementary to our natural gas distribution business. We engage in natural gas asset management and operation of high deliverability natural gas underground storage as adjunct activities to our utility franchises. These businesses allow us to be opportunistic in capturing incremental value at wholesale, 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 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 vitality.

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 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 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.

Proven 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 November 2004 purchase of NUI Corporation (NUI)), a New Jersey-based energy holding company with natural gas distribution operations in New Jersey, Florida, Maryland and Virginia, provides an opportunity to leverage and strengthen one of our core competencies - the efficient, low-cost operation of urban natural gas franchises. The disparity between NUI s pre-acquisition utility operating metrics and cost structure and those of our other utilities suggests we should be able to achieve significant improvements in NUI s business in 2005 and beyond. In addition, our acquisition in October 2004 of the natural gas storage assets of Jefferson Island Storage & Hub LLC (Jefferson Island) as discussed below, added immediate incremental earnings to our business and, given the possibilities for expansion, should provide a stable earnings stream going forward.

Business Accomplishments in 2004

- We increased net income 20 percent to $153 million and diluted earnings per share 13 percent to $2.28 from prior year amounts. In addition to improvements in our base distribution business, we were able to capture additional incremental net income in the wholesale natural gas market through our Sequent asset management, producer services and storage arbitrage activities.
- We strengthened our position as a leading operator of natural gas utility assets in the eastern United States by acquiring NUI.
- We acquired Jefferson Island, a high-deliverability salt-dome gas storage facility in Louisiana, which allows us to migrate into the wholesale market and capitalize on the growing market of utility and large industrial customers, producers, financial intermediaries and marketers who compete to hold firm capacity rights to store natural gas.
- We announced our plan to acquire 250 miles of intrastate pipeline in our Georgia service area from Southern Natural Gas, a subsidiary of El Paso Corporation, which should close in the second quarter of 2005. We expect this acquisition to allow us to, over time, undertake economical reconfiguration of our Georgia transmission grid, integrating gas flows from the Gulf Coast, imported liquefied natural gas (LNG) and our own market area LNG.
- We began construction of a propane-air facility in Virginia that will provide needed peak-day demand protection for the customers of our Virginia Natural Gas, Inc, (Virginia Natural Gas) utility.
- We continued to support a strong balance sheet by issuing 11.04 million shares of AGL Resources common stock in November 2004, raising net proceeds of $332 million primarily to fund the NUI and Jefferson Island acquisitions.
- We increased our dividend 4 percent, for the second consecutive year, to $1.15 per share in 2004. If the current amount per quarter of $0.29 per share would have been in effect for all of 2004, our indicated annual rate would have been $1.16 per share.

Areas of Strategic Focus in 2005

Our business strategy is focused on effectively managing our gas distribution operations, optimizing our return on our assets, selectively growing our gas distribution businesses through acquisitions and developing our portfolio of closely related, unregulated businesses with an emphasis on risk management and earnings visibility. Key elements of our strategy include:

Enhance the value and growth potential of our regulated utility operations We will seek to enhance the value and growth of our existing utility assets by managing our capital spending effectively; pursuing customer growth opportunities in each of our service areas; establishing a national reputation for excellent customer service by investing in systems, processes and people; working to achieve authorized returns in each jurisdiction and, in those jurisdictions where we have performance-based rates, sharing the benefits with our customers; and maintaining earnings and rate stability through regulatory compacts that fairly balance the interests of customers and shareholders.

Rapidly integrate the NUI and Jefferson Island assets and achieve the resulting strategic benefits We are working to integrate NUI s assets into our portfolio of businesses and to provide the associated benefits to our customers and shareholders. Our integration plan includes applying enterprise-wide technology solutions and business processes that are designed to improve the key business metrics we track on a regular basis and bringing NUI s operations to a level of operational and service efficiency comparable to that of our other utility businesses. As part of this process, we also will evaluate certain NUI businesses for possible divestiture, consistent with our philosophy of exiting businesses that do not support our long-term strategy.

Focus on maintaining strong investment-grade profile and high level of liquidity We will continue to maintain a disciplined approach to capital spending and improving operating margins to optimize cash flow generation. Additionally, we seek to reduce in the near term our ratio of total debt to total capitalization in order to strengthen our balance sheet and allow us to respond to the capital needs of our operating businesses. We understand the importance of maintaining strong, investment-grade credit ratings in order to support our operating and investment needs, and we intend to execute on our strategy in a way that enhances our ability to maintain or improve those ratings.

Achieve appropriate regulatory outcomes that support stable utility earnings We currently are involved in regulatory proceedings in Georgia and Tennessee. In Georgia, Atlanta Gas Light's rate case is in process and expected to be completed by April 30, 2005. In Tennessee, we anticipate receiving a final ruling on our appeal of a 2004 Chattanooga Gas Company (Chattanooga Gas) rate case by January 31, 2005. Achieving favorable outcomes in these cases, and any other formal or informal regulatory proceedings in which we may be involved, is integral to the achievement of our earnings targets.

Selectively evaluate the acquisition of natural gas assets We will selectively examine and evaluate the acquisition of natural gas distribution, gas pipeline or other gas-related assets. Our acquisition criteria include the ability to generate operational synergies, value from near-term earnings contributions and adequate returns on invested capital, while maintaining or improving our investment-grade credit ratings.

Selectively expand our other energy businesses We intend to continue to expand our wholesale services and natural gas storage businesses to provide both disciplined incremental earnings growth for shareholders. Sequent intends to continue providing credits to our utility customers through effective management of our affiliated utility assets. In our asset management business, we intend to grow our business with non-affiliated third parties, as well as the services we provide to our affiliated utilities, by providing producers with markets for their gas commodity; providing end-users with gas supply, storage and asset management options; and arbitraging pipeline and storage assets across various gas markets and time horizons. However, we intend continuing protecting our earnings-at-risk by maintaining our commitment to limited open-position and credit risks and by providing transparency and visibility to regulators under our asset management agreements. As our portfolio of assets and our ability to store more physical gas inventory grow, the volatility of reported earnings from this business may increase. In our high deliverability underground storage business, we will seek to expand the operating capabilities of our existing facilities to provide more flexible and valuable injection and withdrawal capabilities for our customers. Pivotal Jefferson Island, LLC is currently expanding its compression capabilities to enhance the number of times a customer can inject and withdraw natural gas. We will complete and begin operation of our propane peaking facility and look for additional opportunities to provide economical peaking services in the regions in which our utilities operate.

Acquire and retain natural gas customers We continue to focus significant efforts in our distribution operations business on improving our net customer growth trends, despite the industry-wide challenges of rising prices for natural gas and competition from alternative fuels, declining natural gas usage per customer and declining regional load factors. In each of our utility service areas, we will continue to implement programs aimed at emphasizing natural gas as the fuel of choice for customers and maximizing the use of natural gas through a variety of promotional opportunities. We also are focused on similar customer growth initiatives in our SouthStar retail marketing business in Georgia. In addition, we continue to improve the credit quality of our customers in the retail marketing business and will use those techniques to improve credit and collections activities within our regulated utilities.

Continue to improve revenue and cash flow stability We have taken a number of actions in recent years to promote more stable and predictable revenues and cash flows in each of our business segments, as well as to moderate the effects of variable factors, such as weather and natural gas prices, on our business results. Some of the improvements we have initiated include performance-based ratemaking treatment in Georgia; weather normalization adjustment programs in Virginia and Tennessee; more efficient cost management and cash recovery from our environmental response cost (ERC) program in Georgia and reduced credit losses from our retail marketing business. We estimate that in 2005 our spending for property, plant and equipment will be $276 million compared to $264 million in 2004. Our capital expenditures should decrease in successive years by reduced spending related to ERC and pipeline replacement (PRP), two mandated regulatory programs that have required significant expenditures. As a result, we expect to enhance our net cash flow which should provide enhanced financial flexibility around business investment opportunities and potentially a return of capital to investors to provide additional shareholder value.

Regulatory Environment

We are subject to the rate regulation and accounting requirements of various state and federal regulatory agencies in the jurisdictions in which we do business. We are committed to working cooperatively and constructively with the regulatory agencies in these states and the other states where we do business as well as federal regulatory agencies in a way that benefits our customers, shareholders and other stakeholders. We believe the dynamic energy environment in which we operate demands that we maintain an open, respectful and ongoing dialogue with these agencies. This posture is the best way to ensure we are working toward common solutions to the many issues our industry faces. These issues include the changing nature of resource availability, pricing volatility, price levels and their effect on economic development in our service territories, the likelihood of increased importation of LNG and the need for reasonably-priced alternatives for our customers to meet their rapidly growing peak demands. For more information regarding pending federal and state regulatory matters, see "Results of Operations - Distribution Operations" and Results of Operations - Wholesale Services.

Technology Initiatives

We continue to make progress with regard to several of our strategic technology initiatives. During the third quarter of 2004, we implemented new technological tools that enable marketers of natural gas in Georgia (Marketers) to create and input service orders directly into Atlanta Gas Light s systems, eliminating the need for duplicate data entry or three-way calls between the customer, Marketers and our customer call center. This system allowed for a reduction in the number of customer service representatives servicing Marketers in our call center. This system also allowed us to further develop our strategy for the replacement of our customer information system, which should result in less capital investment over time than previously estimated.

In addition, we implemented our new energy trading and risk management (ETRM) system at our Sequent Energy Management, L.P. (Sequent) wholesale subsidiary in the fourth quarter of 2004. The ETRM system is designed to enhance internal controls and provide additional transparency into the activities of Sequent s business. We also anticipate the system to enable Sequent to continue to grow its commercial business without significant growth in support staff.

Internal Controls

Section 404 of the Sarbanes-Oxley Act of 2002 (SOX 404) Compliance SOX 404 and related rules of the SEC require management of public companies to assess the effectiveness of the company s internal control over financial reporting as of the end of each fiscal year, including disclosure of any material weaknesses in the company s internal control over financial reporting that have been identified by management. In addition, SOX 404 requires the company s independent auditor to attest to and report on management s annual assessment of the company s internal control over financial reporting. We have documented, tested and assessed our systems of internal control over financial reporting, as required under SOX 404 and Public Accounting Oversight Board Standard No. 2, An Audit of Internal Control Over Financial Reporting Performed in Conjunction With An Audit of Financial Statements (Standard No. 2), which was adopted in June 2004, to provide the basis for management s report and our independent auditor s attestation on the effectiveness of our internal control over financial reporting as of December 31, 2004.

There are three levels of possible deficiencies in our internal controls over financial reporting that can be identified during our assessment phase, which are:

- an internal control deficiency, which exists when the design or the operation of a control does not allow management or employees, in the normal course of performing their functions, to prevent or detect misstatements on a timely basis;
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a significant deficiency, which exists when an internal controls deficiency or a combination of internal control deficiencies adversely affects our ability to initiate, authorize, record, process or report financial data in accordance with accounting principles generally accepted in the United States of America (GAAP) such that there is a more than remote likelihood that a misstatement of the annual or interim financial statements that is more than inconsequential will not be prevented or detected;

· a material weakness, which exists when a significant deficiency or a combination of significant deficiencies results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

As a result, our assessment could result in two possible outcomes at our reporting date:

· we could conclude that our internal controls over financial reporting were designed and were operating effectively, or

· we could conclude that our internal controls over financial reporting were not properly designed or did not operate effectively. A material weakness that exists at the reporting date would require our assessment to be that our internal controls over financial reporting are not effective, and we would be required to disclose such material weaknesses.

Our independent auditor is now required to issue three opinions annually, beginning with our 2004 consolidated financial statements. First, the auditor must evaluate and opine regarding the process by which we assessed the effectiveness of our internal controls over financial reporting. A second opinion must be issued as to the effectiveness of our internal control over financial reporting. Finally, our independent auditors must issue an opinion, as they normally do, as to whether our consolidated financial statements are fairly presented, in all material respects.

Our assessment of compliance with SOX 404 is ongoing and is therefore incomplete. At the current stage of our assessment process, we have not identified any areas or systems where we believe there will be pervasive control deficiencies that we believe would constitute a material weakness in internal controls. We expect to complete the remaining steps in our assessment of internal controls in time to file our Form 10-K for the year ending December 31, 2004 prior to the SEC reporting deadline. Our Form 10-K will include our assessment of our internal controls, as well as our independent auditor s reports on internal controls. The steps remaining in our assessment consist primarily of completion of certain quarterly and annual controls and testing of these and other remediated controls, and the completion of review and testing by our external auditors. If any deficiencies are encountered during the performance of the remaining procedures, we will likely be unable to remediate these controls since we can not perform additional repetitions for testing.

The scope of our assessment of our internal controls over financial reporting included all of our consolidated entities except those falling under NUI, which we acquired on November 30, 2004, and Jefferson Island, which we acquired on October 1, 2004. In accordance with the SEC s published guidance, we excluded these entities from our assessment as they were acquired late in the year and it was not possible to conduct our assessment between the date of acquisition and the end of the year. SEC rules require that we complete our assessment of the internal control over financial reporting of these entities within one year from the date of acquisition.

NUI Internal Control Weaknesses NUI s external and internal auditors performed audits during its fiscal 2003 and 2004 years that identified material weaknesses in NUI s internal controls. These weaknesses were previously discussed in NUI s filings with the SEC. In March 2004, additional internal control issues and deficiencies were identified in the focused audit of NUI that was conducted at the request of the New Jersey Board of Public Utilities (NJBPU). These deficiencies resulted in a material weakness in internal controls over NUI s financial reporting process and also resulted in a need for NUI to restate certain of its financial statements. The internal control deficiencies reported by NUI that were identified by NUI s external and internal auditors included, but were not limited to, the following:

· General ledger cash account balances were not being reconciled to the bank statements

· General ledger account analyses were not being consistently performed

- A listing of debt covenants was not being maintained
- Comprehensive and formalized accounting and financial reporting policies and procedures did not exist
- Instances were noted where management lacked certain technical accounting and tax expertise that resulted in accounting errors
- The flow of accounting information between business units and corporate accounting was not timely or formalized
- Accounts payable invoice processing procedures needed to be improved
- A formal plan and implementation timetable needed to be developed to address compliance with the certification requirements of SOX 404
- The contract review process was not formally documented, and appropriate procedures had not been developed to ensure timely review of contracts for accounting implications
- There was a lack of adherence to policies and procedures for travel and entertainment expense reimbursements and procurement card expenditures
- The payroll timekeeping and tracking process was manual in nature and prone to errors
- Information technology had a number of areas where formal, documented policies and procedures had not been developed

The focused audit conducted at the request of the NJPBU revealed the following accounting concerns and weaknesses:

- Inappropriate and inaccurate treatment of intercompany payable and receivable balances
- Inappropriate use of a common cash pool
- Lack of a formal cash management agreement
- Weaknesses in internal controls for accounts payable and receivable
- Lack of formal or appropriate policies and procedures in certain accounting functions, and
- The need to audit procedures for fixed asset and continuing property records functions

To address the deficiencies in its internal controls and procedures noted above, NUI expanded its internal controls and procedures to include the additional analysis and other post-closing procedures described below. The company:

- Provided comprehensive in-house training in early fiscal 2004 covering the financial reporting process and internal accounting controls, including NUI s written accounting policies and procedures and a policy on disclosure controls, to individuals who participate in the preparation of the company s financial statements and required disclosures
- Conducted meetings in which NUI s President and CEO, Vice President and CFO, General Counsel and Secretary reviewed and discussed accounting and operational issues to ensure completeness and accuracy of disclosures in NUI s SEC filings
- Requested that NUI s in-house counsel and key financial and operational personnel provide information regarding any known commitments and contingencies that may have financial statement and/ or disclosure implications
- Obtained internal certifications from key accounting and operational personnel indicating that they reviewed drafts of their SEC filings for completeness and accuracy
- Conducted formal meetings, led by NUI s Corporate Controller with participation of key accounting personnel (prior to closing the books of account and filing required reports), to identify and resolve accounting and disclosure issues
- Prepared and distributed to participants involved in the preparation and review of NUI s SEC filings a detailed time schedule outlining key dates and responsibilities for the preparation of financial information and required disclosures
- Completed an audit disclosure checklist to ensure all disclosures required by GAAP and applicable securities laws and regulations were properly addressed
- Assembled supporting documentation for disclosures made in its SEC filings
- Retained external counsel to review drafts of its SEC filings to assist management in ensuring compliance with SEC rules and regulations
- Created documentation, including flowcharts and formal written policies and procedures of NUI s financial reporting process, to assist management with its responsibility to ensure key internal accounting controls are identified and addressed

- Distributed a business ethics policy to all employees requesting their acknowledgement that they received, read and complied with the ethics policy
- Conducted internal audits to evaluate internal accounting controls of key business functions

We have initiated our efforts to assess the systems of internal control related to NUI s business to comply with the requirements of both Sections 302 and 404 of the Sarbanes-Oxley Act of 2002. We believe that material deficiencies in internal controls discussed above related to the NUI business persist and that we are required to address and resolve these deficiencies. Our integration plans with respect to the NUI businesses include the integration and conversion of NUI s accounting systems and internal control processes into our accounting systems and internal control processes, the majority of which we expect to complete during the first quarter of 2005. In addition, we have incorporated the NUI businesses into our disclosure control processes, which include the same or similar activities to those undertaken by NUI management described above, as well as other procedures, in our closing and financial reporting process.

Results of Operations

AGL Resources

We acquired Jefferson Island on October 1, 2004 and of NUI on November 30, 2004. As a result, our financial information and results of operations for 2004 include three months of the acquired operations of Jefferson Island and one month of the acquired operations of NUI. Pursuant to FIN 46R, which we adopted in January 2004, we consolidated all of SouthStar s accounts with our subsidiaries accounts as of January 1, 2004. We recorded Piedmont Natural Gas Company, Inc. s (Piedmont) portion of SouthStar s earnings as a minority interest in our consolidated statements of income and Piedmont s portion of SouthStar s contributed capital as a minority interest on our consolidated balance sheet. We eliminated any intercompany profits between segments.

Revenues We generate nearly all of our operating revenues through the sale, distribution and storage of natural gas. We include in our consolidated revenues an estimate of revenues from natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period. We record these estimated revenues as unbilled revenues on our consolidated balance sheet.

A significant portion of our operations is subject to variability associated with changes in commodity prices and seasonal fluctuations. During the heating season, which is primarily from November through March, natural gas usage and operating revenues are higher since generally more customers will be connected to our distribution systems and natural gas usage is higher in periods of colder weather than in periods of warmer weather. Additionally, commodity prices tend to be higher in colder months. Our non-utility businesses principally use physical and financial arrangements to hedge the risks associated with seasonal fluctuations and changing commodity prices. Certain hedging and trading activities may require cash deposits to satisfy margin requirements. In addition, reported earnings for the wholesale services and energy investment segments reflect changes in the fair value of certain derivatives; these values may change significantly from period to period.

Operating Margin and EBIT We evaluate the performance of our operating segments using the measures of operating margin and EBIT. We believe operating margin is a better indicator than revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally passed directly to our customers. We also consider operating margin to be a better indicator in our 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 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 measures may not be comparable to a similarly titled measure of another company. The following are reconciliations of our operating margin and EBIT to operating income and net income and other consolidated financial information for the years ended December 31, 2004, 2003 and 2002.

UNAUDITED

In millions		**2004**		**2003**		**2002**
Operating revenues	$	1,832	$	983	$	877
Cost of gas		994		339		268
Operating margin		838		644		609
Operating expenses						
Operation and maintenance		377		283		274
Depreciation and amortization		99		91		89
Taxes other than income taxes		30		28		29
Total operating expenses		506		402		392
Gain on sale of Caroline Street campus		-		16		-
Operating income		332		258		217
Other income		-		40		30
Minority interest		(18)		-		-
EBIT		314		298		247
Interest expense		71		75		86
Earnings before income taxes		243		223		161
Income taxes		90		87		58
Income before cumulative effect of change in accounting principle		153		136		103
Cumulative effect of change in accounting principle		-		(8)		-
Net income	$	153	$	128	$	103
Basic earnings per common share						
Income before cumulative effect of change in accounting principle	$	2.30	$	2.15	$	1.84
Cumulative effect of change in accounting principle		-		(0.12)		-
Basic earnings per common share	$	2.30	$	2.03	$	1.84
Diluted earnings per common share						
Income before cumulative effect of change in accounting principle	$	2.28	$	2.13	$	1.82
Cumulative effect of change in accounting principle		-		(0.12)		-
Diluted earnings per common share	$	2.28	$	2.01	$	1.82
Weighted average number of common shares outstanding						
Basic		66.3		63.1		56.1
Diluted		67.0		63.7		56.6

2004 compared to 2003 Our earnings per share and net income for 2004 was higher than the prior year due to stronger-than-expected contributions from our wholesale services business and the acquisition of NUI, which closed on November 30. The following table provides a summary of certain items that impacted 2004 earnings.

UNAUDITED

In millions		Increase (Decrease) to 2004 operating income (before taxes)
	$	5

Accelerated recognition of margins associated with Sequent storage positions that originally were anticipated to be liquidated in first quarter 2005.	
Asset sales in the second quarter of 2004 for a residential and retail property in Savannah which resulted in a $2 million contribution to EBIT and the sale of our remaining investment units in U.S. Propane	3
Change in Atlanta Gas Light s property taxes as a result of revised estimates and intangible property tax assessment	3
Contribution to the AGL Resources Private Foundation Inc., and for energy assistance by our subsidiary SouthStar	(3)

The distribution operations segment s EBIT for 2004 was $247 million, equal to 2003 results. For comparison purposes, however, the distribution operations segment s EBIT contribution in 2004 was up $13 million, after excluding the effect of a net $13 million pre-tax gain on the sale of company property and a related charitable contribution in 2003. 2004 EBIT includes a $7 million contribution from NUI.

Operating margins improved by $42 million, primarily as a result of the acquisition of NUI ($25 million) and an approximately 2% increase in the total number of average connected customers at Atlanta Gas Light, Chattanooga Gas and Virginia Natural Gas. Operating expenses increased $29 million in 2004 relative to 2003, primarily as a result of NUI ($19 million) and increased costs related to information technology projects, regulatory activities (including Sarbanes-Oxley compliance) and depreciation expense, offset by decreased bad debt expense and a decrease in costs associated with post-retirement benefits.

The wholesale services segment contributed $24 million in EBIT in 2004, compared with $20 million in 2003. The $4 million increase is primarily the result of unusually strong fourth-quarter 2004 results, reflecting the accelerated recognition of margins associated with storage positions that originally were anticipated to be liquidated in first quarter 2005. The accelerated margin recognition resulted in $5 million of operating income in the fourth quarter that otherwise would have been recognized in first quarter 2005. Primarily as a result of the decline in forward gas prices at the end of December 2004, and the positive mark-to-market impact that decline had on the futures contracts Sequent utilizes to economically hedge its storage positions, approximately $18 million of Sequent s full-year EBIT contribution was generated in the fourth quarter 2004.

Sequent also continued to increase its volumes and business transaction activity in 2004. Full-year volumes were up 20 percent, from 1.75 Bcf per day in 2003 to 2.10 Bcf per day in 2004. New peaking and third-party asset management transactions also contributed to strong results for the year. Sequent s operating expenses for 2004 were $29 million, compared with $20 million in 2003. The increase was due primarily to increased personnel and increased costs associated with the implementation of a new energy trading and risk management system and Sarbanes-Oxley 404 compliance.

The energy investments segment contributed EBIT of $59 million in 2004, a 37 percent increase over the segment s $43 million contribution in 2003. The primary driver of this segment s results was the performance of SouthStar Energy, which contributed $53 million in EBIT in 2004, compared with $46 million in 2003. The improved results at SouthStar mainly reflect higher commodity margins and decreased bad debt expense during the year. Energy Investments EBIT contribution also increased due to higher contributions from AGL Networks and the acquisition of Jefferson Island in October 2004.

The corporate segment EBIT contribution decreased by $4 million in 2004, primarily the result of costs associated with information technology projects, Sarbanes-Oxley 404 compliance and merger and acquisition related expenses.

Interest expense for 2004 was $71 million; $4 million lower than in 2003. 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.

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Dollars in millions	**2004**	**2003**	**2004 vs. 2003**
Total interest expense	$ 71	$ 75	($4)
Average debt outstanding (1)	1,274	1,255	19
Average rate	5.6%	6.0%	(0.4%)

(1) Daily average of all outstanding debt

Based on variable-rate debt outstanding at December 31, 2004, a 100 basis point change in market interest rates from 3.1% to 4.1% would result in a change in annual pretax interest expense of $5 million. We anticipate our interest expense in the twelve months ending December 31, 2005 will be higher than in the same period in 2004 due to the following:

- higher projected short-term interest rates based upon higher 2005 LIBOR rates
- higher debt balances and higher interest rates from 2004 and 2005 on debt issued for the acquisitions of NUI and Jefferson Island.

The increase in income tax expense of $3 million or 3% for 2004 as compared to 2003 reflects $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 is primarily the result of the income tax adjustments recorded in the third quarter of 2004 in connection with our annual comparison of our filed tax returns to the related income tax accruals. We expect our effective tax rate for the year ending December 31, 2005, to be higher due to the favorable adjustments recorded in 2004 and the higher state income tax rate that will be applicable to earnings from Elizabethtown Gas in the state of New Jersey.

As a result of the company s 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. Current shares outstanding are 76.8 million.

2003 compared to 2002 Net income increased $25 million or 24% from 2002, reflecting higher earnings at each operating segment. EBIT from distribution operations excluding the net gain on the sale of the Caroline Street campus of $13 million increased 4% to $234 million from $225 million in 2002 due to higher operating margins, an increase in the number of connected customers and increased pipeline replacement revenue in 2003. Wholesale services contributed $20 million in EBIT compared to $9 million in 2002. The earnings improvement resulted primarily from Sequent s optimization of various transportation and storage assets and increased physical volumes sold as well as increased margins driven by favorable pricing and market volatility, particularly in the first quarter of 2003.

Energy investments contributed $43 million in EBIT compared to $24 million in 2002. SouthStar accounted for the majority of the increase, and its results were driven primarily by higher operating margins, reduced bad debt expense, our expanded ownership interest in the business and the resolution of an income sharing issue with Piedmont. Our corporate segment s expenses decreased primarily as a result of favorable interest expense and lower average debt balances. The 7 million increase in our weighted average shares outstanding was a result of our 6.4 million share equity offering in February 2003.

The following table shows the impact of the 2003 sale of our Caroline Street campus and the related donation to the private foundation:

UNAUDITED

In millions	**Distribution Operations**	**Corporate**	**Consolidated**

Gain (loss) on sale of Caroline Street campus	$ 21	$ (5)	$ 16
Donation to private foundation	(8)	-	(8)
EBIT	$ $ 13	(5)	8
Income taxes			(3)
Net income			$ 5

The decrease in interest expense of $11 million or 13% for 2003 as compared to 2002 was a result of lower average debt balances, as shown in the following table, due primarily to the proceeds generated from our public offering of 6.4 million shares of common stock in February 2003; repayment of Medium-Term notes, which had higher rates than our bond issuance in July 2003; the benefits of our interest rate swaps; and lower interest rates on commercial paper borrowings.

UNAUDITED *Dollars in millions*	**2003**	**2002**	**2003 vs. 2002**
Total interest expense	$ 75	$ 86	($11)
Average debt outstanding (1)	1,255	1,412	(157)
Average rate	6.0%	6.1%	(0.1%)

(1) Daily average of all outstanding debt

The increase in income tax expense of $29 million or 50% for 2003 compared to 2002 was primarily due to the increase in earnings before income taxes of $61 million or 38% and an increase in our effective tax rate from 36% in 2002 to 39% in 2003. The increase in the effective tax rate for 2003 was primarily due to higher projected state income taxes resulting from a change in Georgia law governing the methodology by which Georgia companies must compute their tax liabilities and to the accrual of deferred tax liabilities related to temporary differences between the book and tax basis of some of our assets.

Consolidation of SouthStar Below are our unaudited pro-forma condensed consolidated balance sheet and statement of income, presented as if SouthStar s balances were consolidated with our subsidiaries accounts as of December 31, 2003. This pro-forma presentation is a non-GAAP presentation; however, we believe this pro-forma presentation is useful to the readers of our financial statements since it presents our prior years revenues and expenses on the same basis as 2004 following our consolidation of SouthStar pursuant to our adoption of FIN 46R. These unaudited pro-forma amounts are presented only for comparative purposes. The eliminations amounts include intercompany eliminations, our investment in SouthStar, SouthStar s capitalization and our equity in earnings from SouthStar.

AGL Resources Inc. and Subsidiaries
Pro-forma condensed consolidated balance sheet
December 31, 2003

UNAUDITED

In millions	**As reported**	**SouthStar**	**Eliminations**	**(Unaudited) Pro-forma**
Current assets	$ 742	$ 174	($11)	$ 905
Property, plant and equipment	2,352	2	-	2,354
Deferred debits and other assets (1)	878	-	(71)	807
Total assets	$ 3,972	$ 176	($82)	$ 4,066
Current liabilities	$ 1,048	$ 75	($11)	$ 1,112
Accumulated deferred income taxes	376	-	-	376
Long-term liabilities	569	-	-	569
Deferred credits	77	-	-	77
Minority interest (2)	-	-	30	30
Capitalization	1,902	101	(101)	1,902
Total liabilities and capitalization	$ 3,972	$ 176	($82)	$ 4,066

(1) Our investment in SouthStar was $71 million.

(2) Minority interest adjusts our balance sheet to reflect Piedmont s portion of SouthStar s contributed capital

AGL Resources Inc. and Subsidiaries
Pro-forma condensed consolidated statement of income
for the year ended December 31, 2003

UNAUDITED

In millions	**As reported**	**SouthStar (1)**	**Eliminations**	**(Unaudited) Pro-forma**
Operating revenues	$ 983	$ 746	($169)	$ 1,560
Operating expenses				
Cost of gas	339	622	(169)	792
Operation and maintenance expenses	283	60	-	343
Depreciation and amortization	91	1	-	92
Taxes other than income	28	-	-	28
Total operating expenses	741	683	(169)	1,255
Gain on sale of Caroline Street campus	16	-	-	16
Operating income	258	63	-	321
Equity earnings from SouthStar	46	-	(46)	-

Donation to private foundation	(8)	-	-	(8)
Other income	2	-	-	2
Interest expense	(75)	-	-	(75)
Minority interest in income of consolidated subsidiary (2)	-	-	(17)	(17)
Earnings before income taxes	223	63	(63)	223
Income taxes	(87)	-	-	(87)
Income before cumulative effect of change in accounting principle	$ 136	$ 63	($63)	$ 136

(1) Includes 100% of SouthStar s revenues and expenses for comparisons of SouthStar s consolidation in 2004.

(2) Minority interest adjusts our earnings to reflect our 80% share of SouthStar s earnings (less Dynegy Inc. s 20% share of SouthStar s income prior to February 18, 2003).

AGL Resources Inc. and Subsidiaries
Pro-forma condensed consolidated statement of income
for the year ended December 31, 2002

UNAUDITED

In millions	As reported	SouthStar (1)	Eliminations	(Unaudited) Pro-forma
Operating revenues	$ 877	$ 630	($171)	$ 1,336
Operating expenses				
Cost of gas	268	515	(171)	612
Operation and maintenance expenses	274	72	-	346
Depreciation and amortization	89	2	-	91
Taxes other than income	29	-	-	29
Total operating expenses	660	589	(171)	1,079
Operating income	217	41	-	258
Equity earnings from SouthStar	27	-	(27)	-
Other income	3	1	-	4
Interest expense	(86)	-	-	(86)
Minority interest in income of consolidated subsidiary (2)	-	-	(15)	(15)
Earnings before income taxes	161	42	(42)	161
Income taxes	(58)	-	-	(58)
Net income	$ 103	$ 42	($42)	$ 103

(1) Includes 100% of SouthStar s revenues and expenses for comparisons of SouthStar s consolidation in 2004.

(2) Minority interest adjusts our earnings to reflect our 50% share of SouthStar s earnings.

Distribution Operations

Distribution operations includes our natural gas local distribution utility companies which construct, manage and maintain natural gas pipelines and distribution facilities and serve more than 2.2 million end-use customers. Distribution operations revenues contributed 61% of our consolidated revenues for 2004, 95% of our consolidated revenues for 2003 and 97% for 2002. The decrease of 34% in the contribution of distribution operations revenues from 2003 is due to the impact of our consolidation of SouthStar in 2004. The following table provides operational information for our larger utilities. The daily capacity represents total system capability. The storage capacity includes on-system LNG and propane volumes.

UNAUDITED	Atlanta Gas Light	Elizabethtown Gas	Virginia Natural Gas	Florida Gas	Chattanooga Gas
Average end-use customers (1)	1,533,000	266,000	256,000	104,000	60,000
Daily capacity (2)	2.5	0.4	0.4	0.1	0.2
Storage capacity (2)	55.6	14.0	10.2	-	4.8
2004 peak day demand (2)	1.8	0.4	0.3	.04	0.1
Average monthly throughput (2)	19.8	5.0	2.9	0.8	1.4
Authorized return on rate base	9.16%	7.95%	9.24%	7.36%	7.43%
Authorized return on equity	10.0-12.0%	10.0%	10.0-11.4%	11.25%	10.2%
Estimated 2004 return on equity	11.23%	6.17%	11.44%	6.61%	9.63%

(1) Represents an average for 2004 except Elizabethtown Gas and Florida Gas which are December 2004 amounts
(2) In millions of dekatherms

Each utility operates subject to regulations provided by the state regulatory agencies 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 for the 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. We continuously monitor the performance of our utilities to determine whether rates need to be adjusted by making a rate case filing.

Competition Our distribution operations businesses face competition based on our customers preferences for natural gas compared to other energy products and the comparative prices of those products. Our principal competition relates to the 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. Also, price volatility in the wholesale natural gas commodity market has resulted in increases in the cost of natural gas billed to customers.

Competition for space heating and general household and small commercial energy needs generally occurs at the initial installation phase when the customer/builder typically makes decisions as to which types of equipment to install and operate. The customer will generally continue to use the chosen energy source for the life of the equipment. Our customers demand for natural gas and the level of business of natural gas assets 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 2004, our distribution operation segment s customers grew by approximately 2%. However, in some of our service areas, primarily in Georgia, growth continues to be limited due to the number of customers who choose to leave our systems. We expect our 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.

Our distribution operation utilities include:

Atlanta Gas Light is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. Atlanta Gas Light has approximately 6 billion cubic feet (Bcf) of liquefied natural gas (LNG) storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. 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 the end use customers in Georgia and are handling customer billing functions. Atlanta Gas Light's role includes:

- Distributing natural gas for the Marketers
- Constructing, operating and maintaining the gas system infrastructure, including responding to customer service calls and leaks
- Performing meter reading and maintaining underlying customer premise information for the 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.

Performance-Based Rates Atlanta Gas Light s revenues are established pursuant to a three-year performance-based rate (PBR) plan that became effective May 1, 2002, with an authorized return on equity of 11%. The PBR plan also establishes an earnings band based on a return on equity of 10% to 12%, subject to certain adjustments, with three-quarters of any earnings above a 12% return on equity shared with Georgia customers and one-quarter retained by Atlanta Gas Light.

The Georgia Commission staff has reviewed the operation of the plan and Atlanta Gas Light s revenue requirement to determine whether base rates should be reset upon the expiration of the existing plan in April 2005. The Georgia Commission will then determine whether the plan should be discontinued, extended or otherwise modified.

In connection with this review, Atlanta Gas Light filed with the Georgia Commission a general rate case request for a $26 million rate increase. The request would continue the PBR plan and include a return on equity band of 10.2% to 12.2%. The Georgia Commission is scheduled to issue its decision on April 28, 2005, with any rate adjustments to be effective May 1, 2005. Any rate adjustments would be comprised of changes from May 1, 2002 and projected through April 30, 2005 related to depreciation expense, capital expenditures and various other operating expenses such as pipeline integrity costs mandated by federal regulations and changes in the property tax valuation method.

Pipeline Replacement Program (PRP) Pursuant to the Georgia Commission s revised procedural and scheduling order, Atlanta Gas Light s rate case filing included testimony on whether the PRP should be included in Atlanta Gas Light s base rates or whether the rider currently used for recovery of PRP expenses should be otherwise modified or discontinued. Atlanta Gas Light s testimony supported continuing the current PRP rider agreement. Including the PRP capital costs in base rates before the end of the program would result in a regulatory delay in recovery of our total unrecovered PRP regulatory asset of $361 million. This delay could require more frequent rate requests to fund the annual cost of PRP capital expenditures and resulting depreciation. In addition, the future loss of a recovery mechanism could impair the PRP regulatory asset. Any resulting impairment would reduce Atlanta Gas Light s earnings.

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 will be connected in periods of colder weather than in periods of warmer weather.

Interstate pipeline acquisition Atlanta Gas Light has executed an agreement with Southern Natural Gas (Southern Natural), a subsidiary of El Paso Corporation, to acquire a portion of SNG s interstate pipeline that runs from Macon, Georgia to the vicinity of Atlanta, Georgia. The transaction is valued at approximately $32 million. As part of the agreement, Atlanta Gas Light will extend certain existing SNG transportation and storage contracts to ensure reliable delivery of natural gas into Georgia in return for the right to expand Atlanta Gas Light s system off of the purchased facilities. On January 19, 2005, the Federal Energy Regulatory Commission approved the abandonment of Southern Natural s facilities to Atlanta Gas Light, thereby allowing the transaction to proceed to closing. We expect the Southern Natural transaction to close by April 30, 2005, subject to securing the remaining regulatory approvals.

Capacity Supply Plan In May 2004, Atlanta Gas Light and 8 of the 10 Marketers entered into a settlement that resolved matters related to a capacity supply plan that was required to be filed by Atlanta Gas Light in July 2004. As a result of the settlement, the parties filed with the Georgia Commission a three year capacity supply plan for the Georgia market. In October 2004, we received reconsideration and approval by the Georgia Commission of the capacity supply plan, which includes, among other things:

- calculation of the design (peak) day requirements for the next three years
- purchase by Atlanta Gas Light of the above-described SNG facilities and the recovery of those costs through the pending rate case
- construction of a pipeline from the Macon LNG facility to the purchased SNG facilities
- extension of the Sequent peaking contract to March 2005
- approval of Sequent s current asset management contract for retained assets through March 1, 2006, and
- other tariff provisions

Elizabethtown Gas Company (Elizabethtown Gas) is a natural gas local distribution utility that we acquired with our NUI acquisition, with distribution systems and related facilities in central and northwestern New Jersey. Elizabethtown Gas has an LNG storage and vaporization facility to supplement the supply of natural gas during peak usage periods. The facility has a daily capacity of 24,200 million cubic feet (Mcf) and storage capacity of 131,000 Mcf. Most of 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 northwest region of the state, customer additions are driven primarily by new construction. Elizabethtown Gas is regulated by the NJBPU.

On November 9, 2004, the NJBPU approved our acquisition of NUI and our agreement with the NJBPU s staff and certain third parties related to post-closing operations. This agreement provided, among other things, for:

- a freeze of Elizabethtown Gas base rates for five years, with earnings over an 11% return of equity to be shared with ratepayers in the fourth and fifth years
- Sequent to serve as asset manager for Elizabethtown Gas, beginning April 1, 2005, for a three year term for an annual fixed fee payment by Sequent to Elizabethtown Gas of $4 million
- new performance standards with respect to customer satisfaction, safety and reliability, with negotiations with the various interested parties of the applicable standards beginning in February 2005
- payment of the outstanding balances due on Elizabethtown Gas $28 million refund to its ratepayers and a related $2 million penalty to the NJBPU, and
- a commitment to make $9 million available for the purpose of enhancing severance packages for certain employees located in New Jersey

Weather normalization Elizabethtown Gas tariff contains a weather normalization clause that is designed to help stabilize Elizabethtown Gas results by increasing amounts charged to customers when weather has been 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 the 20 year average of weather conditions.

Virginia Natural Gas is a natural gas local distribution utility with distribution systems and related facilities in southeastern Virginia. Virginia Natural Gas owns and operates approximately 155 miles of a separate high-pressure pipeline that provides delivery of gas to customers under firm transportation agreements within the state of Virginia. Virginia Natural Gas also has approximately five million gallons of propane storage capacity in its two propane facilities to supplement the supply of natural gas during peak usage periods. Virginia Natural Gas is regulated by the Virginia State Corporation Commission (Virginia Commission).

Weather normalization adjustment (WNA) On September 27, 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 Virginia Natural Gas WNA program for an additional two years with certain modifications to the existing program. The significant modifications include the 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.

Propane Air Facility In June 2004, the Virginia Commission issued its final order authorizing the recovery of all charges for the services of a propane air facility through Virginia Natural Gas gas cost recovery mechanism. The approval is for an initial 10-year term, with the possibility of renewal thereafter for terms of two years subject to Virginia Commission approval. The facility will provide Virginia Natural Gas with 28,800 dekatherms of propane air per day on a 10-day-per-year basis to more reliability serve its peaking needs.

Florida City Gas Company (Florida Gas) is a natural gas local distribution utility that we acquired with our NUI acquisition. Florida Gas has distribution systems and related facilities in central and southern Florida. Florida 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 Gas is regulated by the Florida Public Service Commission (Florida Commission).

In January 2004, Florida Gas received approval from the Florida Commission to increase its base rates by approximately $7 million, effective February 23, 2004. The increase represents a portion of Florida Gas request for a rate increase to cover the costs of investments in its customer service assets, system maintenance and growth and increases in its operating expenses.

Chattanooga Gas is a natural gas local distribution utility with distribution systems and related facilities in the Chattanooga and Cleveland areas of Tennessee. Chattanooga Gas has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. Included in the base rates charged by Chattanooga Gas is 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 January 2004, Chattanooga Gas filed a rate plan request with the Tennessee Authority for a total rate increase of approximately $5 million annually. The rate plan was filed to cover Chattanooga Gas rising cost of providing natural gas to its customers. In May 2004, the Tennessee Authority suspended the increase until July 28, 2004 and subsequently deferred the decision to August 30, 2004. After its initial filing, Chattanooga Gas reduced its rate plan increase to approximately $4 million, primarily as a result of the February 2004 Tennessee Authority ruling discussed in Purchased Gas Adjustment below. Chattanooga Gas received a written order from the Tennessee Authority on October 20, 2004 that authorized new rates based on a 7.43% return on rate base for an increase in revenues of approximately $1 million annually. In November 2004, the Tennessee Authority granted Chattanooga Gas motion for reconsideration of the rate increase and in December 2004 heard oral arguments on the issues of the appropriate capital structure and the return on equity to be used in setting Chattanooga Gas rates. The Tennessee Authority has not yet issued its ruling after reconsideration, but it is anticipated that this ruling will be received on January 31, 2005.

Purchased Gas Adjustment In March 2003, Chattanooga Gas filed a joint petition with other Tennessee distribution companies requesting the Tennessee Authority issue a declaratory ruling that the portion of uncollectible accounts directly related to the cost of its natural gas is recoverable through a Purchased Gas Adjustment (PGA) mechanism. The PGA mechanism allows the local distribution companies to automatically adjust their rates to reflect changes in the wholesale cost of natural gas and to insure the utilities recover 100% of the cost incurred in purchasing gas for their customers. On February 9, 2004, the Tennessee Authority ruled that the gas portion of accounts written-off as uncollectible after March 10, 2004 could be recovered through the PGA.

Elkton Gas Company (Elkton Gas) is a natural gas local distribution utility that we acquired with our NUI acquisition. Elkton Gas has distribution systems and related facilities serving approximately 5,600 customers in Cecil County, Maryland. Elkton Gas customers are approximately 70% commercial and industrial and 30% residential. Elkton Gas current rates were authorized in June 1992 by the Maryland Public Service Commission (Maryland Commission).

Virginia Gas Distribution Company is a natural gas local distribution utility that we acquired with our NUI acquisition. Virginia Gas Distribution Company services approximately 300 customers in franchised territories in the southwestern Virginia counties of Buchanan and Russell. Approximately 96% of its natural gas sales are to commercial and industrial customers with its remaining sales to residential customers. Virginia Gas Distribution Company is regulated by the Virginia Commission.

Results of Operations for our distribution operations segment for the years ended December 31, 2004, 2003 and 2002 are shown in the following table:

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In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	$ 1,111	$ 936	$ 852	$ 175	$ 84
Cost of gas	470	337	267	133	70
Operating margin	641	599	585	42	14
Operation and maintenance expenses	286	261	255	25	6
Depreciation and amortization	85	81	82	4	(1)
Taxes other than income	24	24	25	-	(1)
Total operating expenses	395	366	362	29	4
Gain on sale of Caroline Street campus	-	21	-	(21)	21
Operating income	246	254	223	(8)	31
Donation to private foundation	-	(8)	-	8	(8)
Other income	1	1	2	-	(1)
Total other (loss) income	1	(7)	2	8	(9)
EBIT	$ 247	$ 247	$ 225	$ -	$ 22
Metrics					
Average end-use customers (in thousands) (1)	1,880	1,838	1,824	2%	1%
Operation and maintenance expenses per customer	$ 152	$ 142	$ 140	7	1
EBIT per customer (2)	$ 131	$ 127	$ 123	3	3
Throughput (in millions of dekatherms) (1)					
Firm	194	190	182	2%	4%
Interruptible	105	109	124	4	(12)
Total	299	299	306	-	(2)
Heating degree days (3):					
Florida (1)	239	-	-%		-%
Georgia	2,589	2,654	2,812	(2)	(6)
Maryland (1)	860	-	-	-	-
New Jersey (1)	873	-	-	-	-
Tennessee	3,010	3,168	3,052	(5)	4
Virginia	3,214	3,264	3,030	(2)	8

(1) Represents information only for December 2004 for the utilities acquired from NUI.

(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 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.

2004 compared to 2003 There was no change in the distribution operations segment s EBIT from 2003, however, the 2003 results includes a 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 increased $13 million or 5% due to increased operating margin that was partially offset by increased operating expenses.

The increase in operating margin of $42 million or 7% from 2003 includes $17 million combined in increase at Atlanta Gas Light and Virginia Natural Gas. The increase in Atlanta Gas Light s operating margin was primarily from 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 Virginia Natural Gas operating margin was primarily from customer growth. The acquisition of NUI added $25 million of operating margin primarily from its December operations of Elizabethtown Gas and Florida Gas.

Operating expenses increased $29 million or 8% from 2003. This was due primarily to the addition of NUI operations for the month of December of $19 million. The remaining increase of $10 million was due to increases in the cost of outside services related to increased information technology services expenses 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 from new depreciation rates implemented for Virginia Natural Gas and increased assets at each utility. These increases were partially offset by a reduction in bad debt expenses which was primarily due to a Tennessee Authority ruling that allows 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.

2003 compared to 2002 EBIT increased $22 million or 10% for 2003 as compared to 2002, primarily as a result of the gain, net of donation, of $13 million on the sale of our Caroline Street campus which is described above. Excluding the gain and donation, EBIT increased $9 million or 4% from increased operating margin, partially offset by increased operating expenses.

Operating margin increased $14 million or 2% from 2002. This was due primarily to an increased number of customers and a higher usage per degree day, of which Virginia Natural Gas contributed approximately $12 million. Atlanta Gas Light s PRP rider revenues increased $2 million, resulting from recovery of prior-year program expenses, and Atlanta Gas Light s carrying costs charged to Marketers for gas stored underground contributed approximately $1 million due to higher storage volumes. Offsetting these increases was a reduction in Atlanta Gas Light s rates as compared to prior year of $3 million for the first four months of 2003 due to the PBR settlement agreement with the Georgia Commission effective May 1, 2002. Chattanooga Gas operating margin for 2003 was not materially different from 2002.

Operating expenses increased $4 million or 1% from 2002 due primarily to a $2 million increase in corporate allocated costs related to an increase in corporate building lease costs and higher general business insurance premiums. Bad debt expenses increased $2 million, primarily as a result of colder-than-normal weather and higher natural gas prices. Additional increases in operating expenses were attributed to a $1 million Virginia Natural Gas regulatory asset write-off in 2003. These increases in operating expenses were partially offset by a $1 million decrease in depreciation expenses due to lower depreciation rates at Atlanta Gas Light for the first four months of 2003 as a result of the PBR settlement agreement with the Georgia Commission.

Wholesale Services

Wholesale services consists of Sequent, our subsidiary involved in asset optimization, transportation and storage, producer and peaking services and wholesale marketing. Our asset optimization business focuses on capturing 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 with natural gas from the major producing regions and market hubs primarily in the Eastern and Mid-Continental United States. 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 the other alternatives available to its end-use customers.

Asset management transactions Our asset management customers include Atlanta Gas, Chattanooga Gas and Virginia Natural Gas, nonaffiliated utilities, municipal customers and industrial customers. These customers must 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 for a much shorter period. We enter into agreements with these customers, either through contract assignment or agency arrangement, whereby we use their rights to transportation and storage services during periods when they do not need them. We capture margin by optimizing the purchase, transportation, storage and sale of natural gas, and we typically either share profits with customers or pay them a fee for using their assets. On April 1, 2005, in connection with the acquisition of NUI, Sequent plans to commence asset management responsibilities for Elizabethtown Gas, Florida Gas and Elkton Gas. The contract terms are currently being negotiated.

We have reached the following agreements with the Virginia, Georgia and Tennessee state regulatory commissions to clarify Sequent s role as asset manager for our regulated utilities. Failure to renew these agreements on terms substantially similar to the current terms would, over time, have a significant impact on Sequent s EBIT if other customers and assets were not found to replace our utility asset management earnings.

- In November 2000, the Virginia Commission approved an asset management agreement that provides for a sharing of profits between Sequent and Virginia Natural Gas customers. This agreement expires in October 2005, unless Sequent, Virginia Natural Gas and the Virginia Commission agree to extend the contract. In December 2004, we contributed approximately $3 million to Virginia Natural Gas customers for the contract year November 2003 through October 2004. This contribution is being reflected as a reduction to customers gas cost in 2005. We commenced discussions as to the mutually acceptable terms under which this agreement could be extended.
- Various Georgia statutes require Sequent, as asset manager for Atlanta Gas Light, to share 90% of its earnings from capacity release transactions with Georgia s Universal Service Fund (USF). A December 2002 GPSC order requires net margin earned by Sequent, for transactions involving Atlanta Gas Light assets other than capacity release, to be shared equally with the USF. In 2004, we contributed approximately $4 million to the USF based upon profits earned in the last six months of 2003 and for the first six months of 2004.
- In June 2003, Chattanooga Gas tariff was amended effective January 1, 2003 to require all net margin earned by Sequent for transactions involving Chattanooga Gas assets to be shared equally with Chattanooga Gas ratepayers. This agreement expires in April 2006 and is subject to automatic extensions unless specifically terminated by either party. In 2004, Sequent contributed approximately $1 million to Chattanooga Gas customers based upon profits earned in 2003. This contribution was reflected as reduction to customers gas costs in 2004.

Transportation and storage transactions In our wholesale marketing and risk management business, Sequent also contracts for 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 and markets to which we have access and seek out 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 as prices for future delivery periods at many locations are readily available. 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 and by recognizing 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 the producers 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 Wholesale services generates operating margin through, among other things, the sale of peaking services, which includes receiving a fee from affiliated and non-affiliated customers that guarantees that those customers will receive gas under peak conditions. Wholesale services incurs costs to support our obligations under these agreements, which will be 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. Sequent has historically been successful in obtaining new asset management business by placing bids that were based primarily on the intrinsic value of the transaction, which is the difference in commodity prices between time periods or locations at the inception of the transaction.

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.

Business expansion Sequent has been focusing on expanding its business, both geographically and through added emphasis on the origination of new asset management transactions and growing the producer services businesses. Throughout 2004 we added personnel to focus specifically on these opportunities and continued to execute additional nonaffiliated asset management transactions. Our business territory now extends from Texas to Illinois and most other areas of the United States east of the Mississippi River.

This expansion, as well as our other business growth, has increased Sequent s fixed cost commitments in the form of firm capacity charges for transportation and storage contracts and has lengthened the average tenure of our portfolio to nine months at December 31, 2004 from seven months at December 31, 2003. At December 31, 2004, Sequent s longest-dated contract in its portfolio was 23 years and was obtained as part of the NUI acquisition. Excluding this contract, Sequent s portfolio contains transactions with contract terms ranging from one day to eight years. At December 31, 2004, Sequent s firm capacity commitments were:

UNAUDITED In millions	Contract from NUI acquisition	Other	Total

2005	$ 5	$ 8	$ 13
2006	5	2	7
2007 and thereafter	107	9	116

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 expected higher margins in the first and fourth quarters.

Business outlook Continued growth of the nonaffiliated asset management and producer services business lines will be critical to Sequent s success in 2005. Despite the consolidations within the industry, many entities are reluctant to turn over the marketing of their gas or their assets to a major competitor and may favor an independent wholesale services provider. In addition, many utilities are seeking incremental services to meet peak day needs, which is an area of core expertise for Sequent.

We manage our business with limited open positions and limited value at risk (VaR). However, the rescission of EITF 98-10 and our adoption of EITF 02-03 in 2003 have increased earnings volatility in our reported results, as more fully discussed below. Given significant underlying volatility in gas commodity prices, we expect volatility in our earnings to continue.

Energy marketing and risk management activities We accounted for derivative transactions in connection with our energy marketing activities on a fair value basis in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), and prior to 2003 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10.

Under these methods, we recorded 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. We also recorded energy-trading contracts, as defined under EITF 98-10, on a mark-to-market basis for transactions executed on or before October 25, 2002. Energy-trading contracts entered into after October 25, 2002 were recorded on an accrual basis as required under EITF 02-03 s rescission of EITF 98-10, unless they were derivatives that must be recorded at fair value under SFAS 133.

Effective January 1, 2003, we adopted EITF 02-03 (which rescinded EITF 98-10) which had the following effects:

- Contracts that do not meet the definition of a derivative under SFAS 133 are not marked to fair market value.
- Revenues are shown in the income statement 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 recorded an adjustment to the carrying value of our non-derivative trading instruments (principally our storage capacity contracts) to zero, and we now account for them using the accrual method of accounting.
- We recorded an adjustment to the value of our natural gas inventories used in wholesale services to the lower of average cost or market; we previously recorded them at fair value. This resulted in the cumulative effect of a change in accounting principle in our statement of consolidated income for the three months ended March 31, 2003 of $13 million ($8 million net of taxes), which resulted in a decrease of $13 million to our energy marketing and risk management assets and a decrease in accumulated deferred income taxes of $5 million in our accompanying consolidated balance sheet.
- We reclassified our trading activity on a net basis (revenues net of costs) effective July 1, 2002 as a result of the first consensus of EITF 02-03. This reclassification had no impact on our previously reported net income or shareholders equity. Revenues for all periods are shown net of costs associated with trading activities.

As discussed in the chart below, Sequent recorded net unrealized gains related to changes in the fair value of derivative instruments utilized in our energy marketing and risk management activities of $22 million during 2004, $1 million during 2003, excluding the cumulative effect of a change in accounting principle, and $4 million in 2002. The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2004, 2003 and 2002 and provide details of the net fair value of contracts outstanding as of December 31, 2004. Sequent s storage positions are affected by price sensitivity in the NYMEX average price.

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In millions	**2004**	**2003**	**2002**
Net fair value of contracts outstanding at beginning of period	($5)	$ 7	$ 3
Cumulative effect of change in accounting principle	-	(13)	-
Net fair value of contracts outstanding at beginning of period, as adjusted	(5)	(6)	3
Contracts realized or otherwise settled during period	11	2	(5)
Change in net fair value of contract gains (losses)	11	(1)	9
Net fair value of new contracts entered into during period	-	-	-
Net fair value of contracts outstanding at end of period	$ 17	($5)	$ 7

The sources of our net fair value at December 31, 2004 are as follows:

In millions	**Maturity Less than 1 Year**	**Maturity 1-3 Years**	**Maturity 4-5 Years**	**Maturity in Excess of 5 Years**	**Total Net Fair Value**
Prices actively quoted (1)	$ 6	$ 1	$ -	$ -	$ 7
Prices provided by other external sources	$ 10	$ -	$ -	$ -	$ 10

(1) The prices actively quoted category represents Sequent s positions in natural gas, which are valued exclusively using NYMEX futures prices. Prices provided by other external sources are basis transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Our basis spreads are primarily based on quotes obtained either directly from brokers or through electronic trading platforms.

Mark-to-market versus lower of average cost or market We purchase gas for storage when the current market price we pay for gas plus the cost to store the gas is less than the market price we could receive in the future. We attempt to mitigate substantially all of our commodity price risk associated with our storage gas portfolio. We use derivative instruments to reduce the risk associated with future changes in the price of natural gas. We sell NYMEX futures contracts or other over-the-counter derivatives in forward months to substantially lock-in the profit margin we will ultimately realize when the stored gas is actually sold.

Gas stored in inventory is accounted for differently than 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 profit margin is essentially unchanged from the date the transactions were consummated. Gas that we purchase and inject into storage is accounted for at the lower of average cost or market. The derivatives we use to mitigate commodity price risk are accounted for at fair value and marked to market each period. These differences in our accounting treatment, including the accrual basis for our gas storage inventory versus fair value accounting for the derivatives used to mitigate commodity price risk, can result in volatility in our reported earnings.

Earnings volatility and price sensitivity Over time, gains or losses on the sale of gas storage inventory will be offset by losses or gains on the derivatives used as hedges, resulting in the realization of the profit margin we expected when we entered into the transactions. Accounting differences cause Sequent s earnings on its storage gas positions to be affected by natural gas price changes, even though the economic profits remain essentially unchanged. Based upon our storage positions at December 31, 2004, a $0.10 change in the forward NYMEX prices would result in a $0.3 million impact to Sequent s EBIT. As Sequent s storage position increases, its earnings volatility may also increase. At year end, if all of Sequent s storage had been full a $0.10 change in forward NYMEX prices would have resulted in a $0.7 million impact to its earnings.

In addition, if we were to value the gas inventory at fair value, with the change in fair value during the year reflected in earnings, Sequent s EBIT would have increased, net of applicable regulatory sharing, by $1 million and $3 million for the years ended December 31, 2004 and 2003. This is based on a difference between fair value and average cost of $2 million and $5 million for 2004 and 2003. We used a calculation to compare the forward value using market prices at the expected withdrawal period with the cost of inventory included in the balance sheet to determine fair value. The fair value is not reflected in the financial statements due to the accounting rules now in effect.

Storage inventory outlook The NYMEX forward curve graph set forth below reflects the NYMEX natural gas prices as of September 30, 2004 and December 31, 2004 for the period of January 2005 through November 2005. The curve reflects the prices at which we could buy natural gas at the Henry Hub for delivery in the same time period. (Note: January 2005 futures expired on December 28, 2004; however, they are included as they coincide with the January 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 for their price benchmark for spot trades of natural gas.

The NYMEX forward curve graph also displays the significant decline in first quarter 2005 NYMEX prices experienced during the fourth quarter of 2004. As shown in the tables following the graph, the majority of our inventory in storage as of December 31, 2004 is scheduled for withdrawal in early 2005. Since we have these NYMEX contracts in place our original economic profit margin is unaffected. However, the decline in NYMEX prices during the fourth quarter of 2004 resulted in unrealized gains associated with our NYMEX contracts. During the fourth quarter of 2003, we experienced the opposite occurrence when NYMEX prices were increasing, In 2003, our near-term profits declined because our future period hedges were at values lower than the prevailing market prices for the months in which we held the NYMEX contracts. See further discussions in Results of Operations below.

As shown in the table below, Open futures NYMEX contracts represents the volume in contract equivalents of the transactions we executed to economically hedge our storage inventory and lock in our margin. Each contract equivalent represents 10,000 million British thermal units (MMBtu s). As of December 31, 2004, the expected withdrawal schedule of this inventory is reflected in items (2) and (3). At December 31, 2004, the weighted average cost of gas (WACOG) in salt dome storage is $5.83, and the WACOG for gas in reservoir storage is $5.88.

The table also reflects that our storage inventory is fully hedged with futures, which results in an overall locked-in margin, timing notwithstanding. Expected gross margin after regulatory sharing reflects the gross margin we would generate in future periods based on the forward curve and inventory withdrawal schedule at December 31, 2004. Our current inventory level and pricing will result in gross margin of $1 million during 2005. This gross margin could change if we adjust our daily injection and withdrawal plans in response to changes in market conditions in future months.

													Total
(1)	(21)	(105)	(286)	-	-	-	-	-	(2)	(10)	-		(424)
(2)	4	-	-	-	-	-	-	-	-	-	-		4
(3)	17	105	286	-	-	-	-	-	2	10	-		420

	21	105	286	-	-	-	-	-	2	10	-	424
(4)	$0.1	$0.2	$0.8	$-	$-	$-	$-	$-	$-	$-	$-	$1.1

(1) Open futures NYMEX contracts (short) long
(2) Physical salt dome withdrawal schedule
(3) Physical reservoir withdrawal schedule
(4) Expected gross margin, in millions, after regulatory sharing for withdrawal activity

Park and loan outlook Additionally, we have entered into park and loan transactions with various pipelines. A park and loan transaction is a tariff transaction offered by pipelines in which the pipeline allows the customer to park gas on or borrow gas from the pipeline in one period and reclaim gas from or repay gas to the pipeline in a subsequent period. The economics of these transactions are evaluated and price risks are managed similar to the way traditional reservoir and salt dome storage transactions are evaluated and managed. Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. However, these transactions have elements that qualify as and must be accounted for as derivatives in accordance with SFAS 133.

Under SFAS 133, park and loan transactions are considered to be financing arrangements when the contracts contain volumes that are payable or repaid at determinable dates and at a specific time to third parties. Because these park and loan transactions have fixed volumes, they contain price risk for the change in market prices from the date the transaction is initiated to the time the gas is repaid. As a result, these transactions qualify as derivatives under SFAS 133 that must be recorded at their fair value. Certain park and loan transactions that we execute meet this definition. As such, we account for these transactions at fair value once the transaction has started (either the gas is originally parked on or borrowed from the pipeline) and represent the fair value of the derivatives in the consolidated balance sheet as Inventories and reflect the related changes in fair value in our consolidated statement of income.

The table below shows Sequent s park and loan volumes and expected gross margin from park and loans for the indicated periods. Park and (loan) volumes represents the contract equivalent for the volumes of our park and loan transactions as of December 31, 2004 that is not already accounted for at fair value. Expected gross margin from park and loans represents the gross margin from those transactions expected to be recognized in future periods based on the NYMEX forward curves at December 31, 2004.

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In millions	**Jan. 2005**	**Feb. 2005**	**Mar. 2005**	**Apr. 2005**	**May 2005**	**June 2005**	**July 2005**	**Total**
Park and (loan) volumes	(15)	12	6	-	15	(12)	(6)	-
Expected gross margin from park and (loans)	($0.3)	$ 0.3	$ 0.1	-	-	-	-	$ 0.1

Credit rating 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, we would need to post collateral to continue transacting business 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 business with these counterparties would be impaired. If at December 31, 2004, our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $20 million.

Results of Operations for our wholesale services segment for the years ended December 31, 2004, 2003 and 2002 are as follows:

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In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Operating revenues	$ 54	$ 41	$ 23	$ 13	$ 18
Cost of sales	1	1	-	-	1
Operating margin	53	40	23	13	17
Operation and maintenance expenses	27	20	13	7	7
Depreciation and amortization	1	-	-	1	-
Taxes other than income	1	-	1	1	(1)
Total operating expenses	29	20	14	9	6
Operating income	24	20	9	4	11
Other loss		-	-		-
EBIT	$ 24	$ 20	$ 9	$ 4	$ 11
Metrics					
Physical sales volumes (Bcf/day)	2.10	1.75	1.39	20%	26%

2004 compared to 2003 EBIT increased $4 million or 20% from 2003 due to a $13 million increase in operating margin, partially offset by a $10 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 were 2.10 Bcf/day, a 20% increase from the prior year. This increase resulted primarily from the addition of new counterparties, increased presence in the Mid-Continent and Northeast markets and continued growth in origination and asset management activities, as well as the 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 reflect the recognition of gains associated with the financial instruments used to 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 upon 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 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 reflect depreciation associated with the recently implemented ETRM system.

2003 compared to 2002 EBIT increased $11 million or 122% from 2002 primarily due to a $17 million increase in operating margin, offset by an increase of $6 million in operating expenses. The increase of $17 million or 74% in operating margin was due primarily to Sequent s optimization of various transportation and storage assets, mainly in the first quarter when natural gas prices were highly volatile. Sequent s physical sales volumes for 2003 increased 26% to 1.75 Bcf/day as compared to 2002. This increase was partially attributable to Sequent s successful efforts to gain additional new business in the Midwest and Northeast. Additionally, a number of market factors, including colder temperatures during the winter in market areas served by Sequent and reduced amounts of gas in storage as the winter progressed, resulted in increased volatility in Sequent s markets during the first quarter of 2003 compared to the same period of 2002. The volatility in the second and third quarters returned to seasonal averages and increased slightly above average in the fourth quarter.

In the first quarter, Sequent sold substantially all its inventory that was previously recorded on a mark-to-market basis under the now-rescinded EITF 98-10. This resulted in $13 million in realized income, offset by amounts shared with our affiliated LDCs for transactions that were recorded on a mark-to-market basis in prior periods. The increase in operating margin was partly offset by lower natural gas volatility created by unseasonably cool temperatures in the Southeast, Mid-Continent and Upper Mid-Atlantic during the summer of 2003. In the summer of 2002, volatility was higher as a result of two hurricanes in the Gulf of Mexico and warmer-than-normal temperatures in the Northeast.

Operating expenses increased by $6 million or 43%, primarily due to a $3 million increase in corporate costs and a $3 million increase primarily due to personnel and outside consulting costs incurred while growing the business.

Energy Investments

Our energy investments segment includes the results of operations and financial condition of:

SouthStar is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. On March 11, 2003, we purchased Dynegy s 20% ownership interest in a transaction that for accounting purposes had an effective date of February 18, 2003. SouthStar markets natural gas and related services to retail customers, principally in Georgia.

We currently own a non-controlling 70% financial interest in SouthStar, and Piedmont owns the remaining 30%. Our 70% interest is non-controlling because all significant management decisions require approval of both owners. On March 29, 2004, we executed an amended and restated partnership agreement with Piedmont. This amended and restated partnership agreement calls for SouthStar s future earnings starting in 2004 to be allocated 75% to our subsidiary and 25% to Piedmont. In addition, we executed a services agreement which provided that AGL Services Company will provide and administer accounting, treasury, internal audit, human resources and information technology functions for SouthStar.

Competition SouthStar, which operates under the trade name Georgia Natural Gas, competes with other energy marketers, including Marketers in Georgia, to provide natural gas and related services to customers in Georgia and the Southeast. Based upon its market share, SouthStar is the largest retail marketer of natural gas in Georgia with average customers in 2004 in excess of 500,000. This represents a market share of approximately 36% as of December 31, 2004, which is consistent with its market share in 2003 and 2002.

Pivotal Jefferson Island Storage & Hub, LLC (Pivotal Jefferson Island), our wholly-owned subsidiary, operates a storage and hub facility in Louisiana, approximately eight miles from the Henry Hub. We acquired the facility from American Electric Power in October 2004 for an adjusted price of $90 million, which included approximately $9 million of working gas inventory. We funded the acquisition with a portion of the net proceeds we received from our November 2004 common stock offering and short-term debt borrowing.

The storage facility is regulated by the Louisiana Public Service Commission, and by the FERC, the latter of which regulates the storage and transportation services. The facility consists of two salt dome gas storage caverns with 9.4 million Dekatherms (Dth) of total capacity and about 6.9 million Dth of working gas capacity. By increasing the maximum operating pressure, we can periodically increase the working gas capacity to approximately 7.4 million Dth. The facility has approximately 720,000 Dth/day withdrawal capacity and 240,000 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 other pipelines in the area. Pivotal Energy Development (Pivotal Development) is responsible for the day-to-day operation of the facility.

Pivotal Jefferson Island is fully subscribed for the 2004-2005 winter period. Beginning April 1, 2005, approximately 2.5 Bcf of capacity will become available. Marketing of this capacity is ongoing. Pivotal Jefferson Island intends to lease any unsubscribed capacity to one or more customers in 2005, with varying term lengths to create a portfolio of contracts for service. Pivotal Jefferson Island is currently expanding its compression capability to enhance the number of times a customer can inject and withdraw gas. We expect to complete this upgrade in the third quarter of 2005.

Pivotal Propane of Virginia, Inc. (Pivotal Propane), our wholly-owned subsidiary, intends to complete in the first quarter of 2005 the construction of a propane air facility in the Virginia Natural Gas service area to provide it with up to 28,800 Dth of propane air per day on a 10-day-per-year basis to serve Virginia Natural Gas peaking needs. The cold storage tank foundation is complete and construction of the process facility is underway. We expect the plant to be initially available in the first quarter of 2005.

Virginia Gas Company is a natural gas storage, pipeline and distribution company with principal operations in Southwestern Virginia. Virginia Gas Company, through its wholly-owned subsidiary Virginia Gas Pipeline Co., owns and operates a 72-mile intrastate pipeline and operates two storage facilities, a high-deliverability salt cavern facility, Saltville Storage Inc. (Saltville Storage) in Saltville, Virginia, and a depleted reservoir facility in Early Grove, Virginia. Combined, the storage facilities have approximately 2.6 Bcf of working gas capacity. Virginia Gas Pipeline Co. also serves as construction and operations manager for our Saltville Storage joint venture described below.

Saltville Storage is a 50% member of Saltville Gas Storage Company, LLC, a joint venture formed in 2001 with a subsidiary of Duke Energy Corporation (Duke) to develop a high-deliverability natural gas storage facility in Saltville, Virginia and is accounted for under the equity method of accounting. Saltville Storage serves customers in the Mid-Atlantic region. Saltville Storage currently has approximately 1.8 Bcf of storage capacity and is planning an expansion to increase its storage capacity to 5.3 Bcf of working gas with deliverability of up to 500 million cubic feet per day. The expansion is expected to be completed in 2008. Saltville Storage connects to Duke s East Tennessee Natural Gas interstate system and its Patriot pipeline.

All of Virginia Gas Company s businesses are regulated by the Virginia Commission except Saltville Storage, which is regulated by the FERC. As such, Saltville Storage is required to construct and operate its facilities and provide service subject to FERC regulations.

AGL Networks, LLC (AGL Networks), our 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.

Competition AGL Networks competitors exist to the extent that they have, or will lay, conduit and fiber or may install conduit in the future on the same route in the respective metropolitan areas. We believe our footprint in Atlanta and Phoenix are unique continuous rings and, as such, will be subscribed ahead of most competitors as market conditions support greater use of our product.

US Propane LP (US Propane) is a joint venture formed in 2000 by us, Atmos Energy Corporation, Piedmont and TECO Energy, Inc. US Propane owned all the general partnership interests, directly or indirectly, and approximately 25% of the limited partnership interests in Heritage Propane Partners, L.P., a publicly traded marketer of propane. On January 20, 2004, we sold our general and limited partnership interests for $29 million and recognized a gain of $1 million, which we recorded in other income.

Results of operations for our energy investments segment for the year ended December 31, 2004 and pro-forma results as if SouthStar s accounts were consolidated with our subsidiaries accounts for the years ended December 31, 2003 and 2002 are as follows. 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 the reader of our financial statements since it presents prior years revenue and expenses on the same basis as 2004.

In 2003 and 2002, we recognized our portion of SouthStar s earnings of $46 million and $27 million as equity earnings. The increase of $19 million or 70% was primarily due to resolution of an income sharing issue with Piedmont of $6 million, higher volumes and related operating margin, additional 20% ownership interest (which contributed approximately $8 million), and lower bad debt and operating expenses.

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In millions	**2004**	**Pro-forma 2003**	**Pro-forma 2002**	**2004 vs. 2003**	**2003 vs. 2002**
Operating revenues	$ 852	$ 752	$ 632	$ 100	$ 120
Cost of sales	707	622	515	85	107
Operating margin	145	130	117	15	13
Operation and maintenance expenses	65	69	80	(4)	(11)
Depreciation and amortization	4	2	2	2	-
Taxes other than income	1	1	-	-	1
Total operating expenses	70	72	82	(2)	(10)
Operating income	75	58	35	17	23
Other income	2	2	4	-	(2)
Minority interest	(18)	(17)	(15)	(1)	(2)
EBIT	$ 59	$ 43	$ 24	$ 16	$ 19
Metrics					
SouthStar					
Average customers (in thousands)	533	558	564	(4%)	(1%)
Market share in Georgia	36%	38%	38%	(5%)	-

2004 compared to 2003 The increase in EBIT of $16 million or 37% for the year ended December 31, 2004 was primarily due to increased EBIT of $7 million from SouthStar, EBIT of $3 million from Pivotal Jefferson Island, and EBIT of $3 million from AGL Networks. The remaining increase of $3 million was from the sale of Heritage Propane 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 $15 million or 12% primarily as a result of margin increases at SouthStar of $8 million, at Pivotal Jefferson Island of $4 million, and at AGL Networks of $4 million. SouthStar s $8 million margin increase was a result of $9 million increase due primarily to a lower commodity cost structure resulting from continued refinement of SouthStar s hedging strategies, a $3 million increase due to a full year of higher customer service charges from the 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. AGL Networks increase was due to increased revenue from a variety of customers.

Operating expenses decreased by $2 million or 3% primarily due to $6 million lower bad debt expense at SouthStar as a result of ongoing active customer collection process improvements and increased quality of the customer base partially offset by a $5 million increase in corporate allocations and increased costs related to SOX 404 implementation. There was also a $1 million increase in minority interest as a result of higher SouthStar earnings in 2004 as compared to 2003.

2003 compared to 2002 The EBIT increase of $19 million or 79% was primarily due to increased EBIT at SouthStar and US Propane offset by lower AGL Networks earnings.

Operating margin increased $13 million or 11% primarily due to $9 million from increased margin from SouthStar resulting from a $3 million one-time sale of storage, a $3 million increase from higher customer service charges, and a $3 million increase in additional interruptible margin. There was also a $4 million increase in margin from AGL Networks due to a $3 million increase in monthly recurring contract revenues, and a $2 million sales-type lease completed in the first quarter of 2003. This was partially offset by a $1 million of feasibility fee income in 2002; no such fees were recognized in 2003.

The decrease in operating expenses of $10 million or 12% was due primarily to lower bad debt expense at SouthStar of $10 million due to improved delinquency process and customer base and lower operating expenses from a reduction in customer care costs of $3 million. AGL Networks had a $3 million increase in operating expenses due primarily to business growth and higher corporate overhead costs. Other income decreased $2 million due primarily to a contract renewal payment of $2 million associated with the sale of Utilipro.

Corporate

Our corporate segment includes our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital). AGSC is a service company established in accordance with the Public Utility Holding Company Act of 1935, as amended (PUHCA). AGL Capital provides for our ongoing financing needs through its commercial paper program, the issuance of various debt and hybrid securities and other financing arrangements.

In August 2003, we formed Pivotal Energy Development (Pivotal Development) as an operating division within AGSC. Pivotal Development coordinates, among our related operating segments, the development, construction or acquisition of gas related assets in the regions our gas utilities serve or where their gas supply originates in order to extend our natural gas capabilities and improve system reliability while enhancing service to our customers in these areas. The focus of Pivotal Development s commercial activities is to improve the economics of system reliability and natural gas deliverability in these regions as well as acquire and operate natural gas assets that serve wholesale markets, such as underground storage.

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.

Results of operations for our corporate segment for the years ended December 31, 2004, 2003 and 2002 are as follows:

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In millions	2004	2003	2002	2004 vs. 2003	2003 vs. 2002
Total operating expenses	$ 12	$ 6	$ 8	($6)	$ 2
Asset disposal on sale of Caroline Street campus	-	5	-	5	(5)
Operating loss	(12)	(11)	(8)	(1)	(3)
Other losses	(4)	(1)	(2)	(3)	1
EBIT	($16)	($12)	($10)	($4)	($2)

2004 compared to 2003 The decrease in EBIT of $4 million or 33% for the year ended December 31, 2004 as compared to the same period last year primarily was due to an increase in corporate costs, net of corporate allocations, of $8 million resulting from increased operating expenses. The increase in operating expenses was primarily from costs associated with software maintenance, licensing and implementation of our work management system project, a loss on the retirement of information service and facilities assets, higher costs due to our SOX 404 compliance efforts, merger and acquisition related expenses and expenses related to Pivotal Development s activities in 2004.

2003 compared to 2002 The decrease in EBIT of $2 million or 20% for 2003 compared to 2002 was primarily the result of a loss of $5 million on the sale our Caroline Street campus. The decrease was offset by decreased operating expenses of $3 million for 2003 as compared to 2002.

The $2 million decrease in operating expenses was due to charges incurred in 2002 that were not incurred in 2003, which were not allocated to our operating segments in 2002. In 2002, we recorded $6 million for the termination of an automated meter reading contract, $2 million for the write-off of capital costs related to a terminated risk management software implementation project and $2 million in employee severance costs. These decreases were offset by 2003 expenses not allocated to our operating segments, consisting primarily of $5 million in increased compensation and benefit costs.

Liquidity and Capital Resources

We rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreement (Credit Facility); and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. We believe these sources will be sufficient for our working capital needs, including the potential significant volatility of working capital requirements of our wholesale services business, debt service obligations and scheduled capital expenditures for the foreseeable future. The relatively stable operating cash flows of our distribution operations business currently provide most of our cash flow from operations, and we anticipate this to continue in the future. However, we have historically had a working capital deficit, primarily as a result of our borrowings of short-term debt to finance the purchase of long-term assets, principally property, plant and equipment, and we expect this also to continue in the future. Our liquidity and capital resource requirements may change in the future due to a number of 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 rate-making policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement benefit funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks

Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. On April 1, 2004, we received approval from the SEC, under the PUHCA, for the renewal of our financing authority to issue securities through April 2007. Our total cash and available liquidity under our Credit Facility at December 31, 2004 and 2003 is represented in the table below:

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In millions	**Dec. 31, 2004**	**Dec. 31, 2003**
Unused availability under the Credit Facility	$ 750	$ 500
Cash and cash equivalents	49	17
Total cash and available liquidity under the Credit Facility	$ 799	$ 517

The increase in total cash and available liquidity under our Credit Facility of $282 million is due primarily to the amended September 2004 Credit Facility that was increased by $250 million and additional cash from operations at December 31, 2004.

Investing activities Our cash used in investing activities consisted primarily of property, plant and equipment (PP&E) expenditures and our acquisition of NUI and Jefferson Island in 2004. In addition, in 2003, our other investing activities included our cash payment of $20 million for the purchase of Dynegy s 20% interest in SouthStar. In 2002, we received $27 million in cash from SouthStar and US Propane. The following table provides additional information on our actual and estimated PP&E expenditures:

UNAUDITED	Estimated	Actual				
In millions	**2005**	**2004**	**2003**	**2002**	**2004 vs. 2003**	**2003 vs. 2002**
Construction of distribution facilities	$ 87	$ 64	$ 60	$ 62	$ 4	($2)
Pipeline replacement program	85	95	45	48	50	(3)
Pivotal propane plant	2	29	-	-	29	-
Telecommunications	5	5	8	28	(3)	(20)
Other	97	71	45	49	26	(4)
Total PP&E expenditures	$ 276	$ 264	$ 158	$ 187	$ 106	($29)

2004 compared to 2003 The increase of $106 million, or 67%, in PP&E expenditures for 2004 as compared to 2003 was primarily due to increased pipeline replacement program expenditures of $50 million and our investment in the propane plant by Pivotal Propane. In addition, the increase was due to $9 million of expenditures for the construction of the Macon peaking pipeline, $7 million for the ETRM at Sequent, $3 million at Pivotal Jefferson Island and $3 million at SouthStar.

2003 compared to 2002 The decrease of $29 million or 15% in PP&E expenditures for 2003 as compared to 2002 was primarily due to lower telecommunications expenditures of $21 million as a result of the completion of the metro Atlanta fiber network in 2002, and a decrease in construction of distribution facilities of $8 million associated with distribution operations.

2005 compared to 2004 In 2005, we estimate that our total PP&E expenditures will increase as a result of expenditures for construction of distribution facilities of $23 million and the SNG interstate pipeline for $38 million. Our expected increase in the construction of distribution facilities is primarily due to increased expenditures for renewals and the acquired NUI utilities.

Our PRP costs are expected to increase in the next four years primarily as a result of the replacement of larger-diameter pipe than in prior years, the majority of which is located in more densely populated areas. The PRP recoveries are recorded as revenues and are based upon a formula that allows us to recover operation and maintenance costs in excess of those included in Atlanta Gas Light s base rates, depreciation expense and an allowed rate of return on capital expenditures. 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 costs recovery does not match the timing of when costs are incurred. As discussed earlier, Atlanta Gas Light s current rate case includes testimony on whether the PRP should be included in its base rates or whether the rider currently used for recovery of PRP expenses should be otherwise modified or discontinued.

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 senior notes to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable cost or terms. Factors we consider important in assessing our credit ratings: our balance sheet leverage, capital spending, earnings volatility, available liquidity and our overall business risk. 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 January 2005, our credit ratings were BBB+ from Standard & Poor s Rating Services (S&P), Baa1 from Moody s Investor Service and A- from Fitch Ratings (Fitch).

During 2004, no fundamental adverse shift occurred in our ratings profile; however, 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, S&P removed us from Credit Watch and changed our outlook to negative; Fitch took us off Rating Watch Negative and affirmed our ratings with a stable outlook; Moody s affirmed our ratings and kept the negative outlook. S&P and Moody s have indicated 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 assure 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 downgraded our ratings, particularly below investment grade, it may significantly limit our access to 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, minimum net worth, insolvency events, nonpayment of scheduled principal or interest payments, acceleration of other financial obligations and change of control provisions. Our Credit Facility s financial covenants and our PUHCA financing authority require us to maintain a ratio of total debt-to-total capitalization of no greater than 70%; however, our goal is to maintain this ratio at levels between 50% and 60% of debt-to-total-capitalization. We are currently in compliance with all existing debt provisions and covenants.

Short-term Debt Our short-term debt is composed of borrowings under our commercial paper program, Sequent s line of credit and SouthStar s line of credit. 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. In addition, we typically reduce short-term debt balances in the spring because a significant portion of our current assets are converted into cash at the end of the winter heating season.

Our commercial paper program is supported by our Credit Facility, which was amended on September 30, 2004. Under the terms of the amendment, the term of the Credit Facility was extended from May 26, 2007 to September 30, 2009. The aggregate principal amount available under the amended Credit Facility has been increased from $500 million to $750 million, and our option to increase the aggregate cumulative principal amount available for borrowing on not more than one occasion during each calendar year was increased from $200 million to $250 million. As of December 31, 2004 and 2003, 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:

· compliance with certain financial covenants
· the continued accuracy of representations and warranties contained in the agreement
· our total debt-to-capital ratio

Sequent uses its $25 million unsecured line of credit solely for the posting of margin deposits for NYMEX transactions, and it is unconditionally guaranteed by us. This line of credit expires on July 1, 2005 and bears interest at the federal funds effective rate plus 0.5%. At December 31, 2004, the line of credit had an outstanding balance of $18 million.

SouthStar s $75 million line of credit provides the additional working capital needed to meet seasonal demands and is not guaranteed by us. The 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.

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, and 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. As a result of the NUI acquisition, we assumed NUI s obligation with regard to $200 million in revenue bonds.

In 2003, we issued $225 million of 4.45% senior notes due July 2013 and used the net proceeds to repay approximately $204 million of our Medium-Term notes and approximately $21 million of short-term debt. In 2002, we made $93 million in scheduled Medium-Term note payments using a combination of cash from operations and proceeds from our commercial paper program.

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, 2004, including the effects of our interest rate swaps, 72% of our total short-term and long-term debt was fixed.

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 on our consolidated balance sheet and included it as a component of our total capitalization. We also recorded a cash distribution of $14 million for

SouthStar s dividend distribution to Piedmont 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 Pivotal Jefferson Island.

In February 2003, we completed our public offering of 6.4 million shares of common stock. The offering generated net proceeds of approximately $137 million, which we used to repay outstanding short-term debt and for general corporate purposes.

Dividends on Common Stock In April 2004, we announced a 4% increase in our common stock dividend, raising the quarterly dividend from $0.28 per share to $0.29 per share, which equates to an annual dividend of $1.16 per share. In April 2003, we announced a 4% increase in our common stock dividend from $0.27 per share to $0.28 per share, which equates to an annual dividend of $1.12. Our Board of Directors intends to review our dividend policy in the first quarter of 2005.

Shelf Registration In October 2004, we filed a new shelf registration statement with the SEC for authority to increase our aggregate capacity to $1.5 billion of various capital securities. The shelf registration statement was declared effective in November 2004. We currently have remaining capacity under that 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. We evaluate our estimates on an ongoing basis, and our actual results may differ from these 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.

Regulatory Accounting

We account for transactions within our distribution operations segment according to the provisions of SFAS No. 71, Accounting for the Effects of Certain Types of Regulation (SFAS 71). Applying this accounting policy allows us to defer expenses and income in the consolidated balance sheets as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the rate-setting process in a period different from the period in which they would have been reflected in the statements of consolidated income of an unregulated company. We then recognize these deferred regulatory assets and liabilities in our statements of consolidated income in the period in which we reflect the same amounts in rates.

If any portion of distribution operations ceased to continue to meet the criteria for application of regulatory accounting treatment for all or part of its operations, we would eliminate the regulatory assets and liabilities related to those portions ceasing to meet such criteria from our consolidated balance sheets and include them in our statements of consolidated income for the period in which the discontinuance of regulatory accounting treatment occurred.

Pipeline Replacement Program (PRP)

Atlanta Gas Light was ordered by the Georgia Commission to undertake a PRP which will 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 to the Georgia Commission in accordance with this order 2,312 miles of bare steel and cast iron pipe to be replaced. Atlanta Gas Light has subsequently identified an additional 188 miles of pipe subject to replacement under this program. If Atlanta Gas Light does not perform in accordance with this order, it can be assessed certain nonperformance penalties, however, to date, Atlanta Gas Light is in full compliance. 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. 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 $242 million as of December 31, 2004 and $323 million as of December 31, 2003, which represented engineering estimates for remaining capital expenditure costs in the PRP. As of December 31, 2004, Atlanta Gas Light had recorded a current liability of $85 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.

The PRP is also an issue in the current Atlanta Gas Light rate proceeding. It is possible the Georgia Commission may alter the recovery method for the costs we incur or may disallow cost recovery while maintaining the requirement to replace the bare steel and cast iron pipe. Changes to the recovery of PRP costs could result in an impairment of our regulatory asset of $361 million at December 31, 2004, if costs are disallowed or if it is no longer probable that accrued costs would be recoverable from rate payers in the future.

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. In addition, Atlanta Gas Light continues to review technologies available for cleanup of its two largest sites, Savannah and Augusta Georgia, which, if proven, could have the effect of further reducing its total future expenditures.

Our latest available estimate as of September 30, 2004 for those elements of the remediation program with in-place contracts or engineering cost estimates is $36 million. This is a reduction of $30 million from the estimate as of September 30, 2003 of projected engineering and in-place contracts, resulting from $50 million of program expenditures during the 12 months ended September 30, 2004. During this same 12 month period, Atlanta Gas Light realized increases in its future cost estimates totaling $20 million related to an increase in the contract value at Augusta, Florida for treatment of two areas and additional deep excavation of contaminants, the addition of harbor sediment removal at St. Augustine, an increase at Savannah for the phase 2 excavation and a partially offsetting decrease in engineering and oversight costs, and an increase in the program management costs due to legal matters, environmental regulatory activities and oversight costs for the extension of work at Savannah and Augusta. For elements of the remediation program where Atlanta Gas Light still cannot perform engineering cost estimates, considerable variability remains in available estimates. The estimated remaining cost of future actions at these sites is $14 million.

Atlanta Gas Light estimates certain other costs paid directly by it related to administering the remediation program and remediation of sites currently in the investigation phase. Through January 2006, Atlanta Gas Light estimates the administration costs to be $2 million. Beyond January 2006, these costs are not estimable. For those sites currently in the investigation phase our estimate is $9 million, which is based upon preliminary data received during 2004 with respect to the existence of contamination of those sites. Our range of estimates for these sites is from $4 million to $15 million. We have accrued the midpoint of our range, or $9 million, as this is our best estimate at this phase of the remediation process.

The ERC liability is included in a corresponding regulatory asset. As of December 31, 2004, the regulatory asset was $165 million, which is a combination of the accrued ERC 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 estimate also does not include any potential cost savings from the new cleanup technologies referenced above.

In New Jersey, Elizabethtown Gas is currently conducting environmental remedial activities for up to six sites 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 certainty, Elizabethtown Gas has recorded a regulatory liability of approximately $35 million which it believes represents the probable minimum amount it may expend over the next 30 years. Of this amount, approximately $31 million relates to remediation of the New Jersey properties and approximately $4 million is for the anticipated remediation of former NUI sites located in North Carolina, South Carolina, Pennsylvania, Maryland and New York within the next five years.

Our prudently incurred remediation costs for the New Jersey properties have been authorized by the NJBPU to be recoverable in rates through its Remediation Adjustment Clause. As a result, Elizabethtown Gas had recorded a regulatory asset of approximately $35 million, inclusive of interest, as of December 31, 2004, 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. Any change in our estimate for future remediation costs for all these former operating sites, excluding the former NUI sites located outside of New Jersey, would be reflected in our regulatory liability.

Revenue Recognition

Elizabethtown Gas, Virginia Natural Gas, Florida Gas and Chattanooga Gas rate structures include volumetric rate designs that allow recovery of costs through gas usage. These utilities recognize revenues from sales of natural gas and transportation services in the same period in which they deliver the related volumes to customers. These utilities also bill and recognize sales revenues from residential and certain commercial and industrial customers on the basis of scheduled meter readings. In addition, they record revenues for estimated deliveries of gas, not yet billed to these customers, from the meter reading date to the end of the accounting period. We include these revenues in our consolidated balance sheets as unbilled revenue. Furthermore, included in the rates charged by Elizabethtown Gas, Virginia Natural Gas and Chattanooga Gas is a WNA factor, which offsets the impact of unusually cold or warm weather on operating margins.

Purchase Price Allocation

During 2004, we completed two significant acquisitions, Jefferson Island and NUI. We purchased Jefferson Island for an adjusted price of $90 million which included approximately $9 million of working gas inventory. We purchased NUI for $225 million in cash plus the assumption of NUI s outstanding net debt. At closing NUI had $709 million in debt and approximately $109 million of cash on its balance sheet, bringing the net value of the transaction to approximately $825 million.

In accordance with SFAS No. 141, "Business Combinations" (SFAS 141), the purchase price is allocated to the various assets and liabilities acquired at their estimated fair value. Estimating fair values can be complex and can require significant applications of judgmental. It most commonly affects non-regulated property, plant and equipment, non-regulated assets and liabilities, and intangible assets, including those with indefinite lives. Our evaluation of NUI s identifiable assets acquired and liabilities assumed is a preliminary valuation based upon currently available information and is subject to final adjustments. The valuations are considered preliminary since they are based upon limited information available to management and independent appraisers. Generally, we have, if necessary, up to one year from the acquisition date to finalize the purchase price allocation. Any changes in estimates used in the allocation of the purchase price that are made after the one year look back period would be recognized in earnings during the period in which the change in estimate is made.

We expect to record goodwill associated with the acquisitions of Jefferson Island and NUI that will be required to be tested for impairment at least annually in accordance with the requirements of SFAS 142. The goodwill associated with the acquisition of NUI is expected to be allocated to our distribution operations segment. Based on our annual assessment at December 31, 2004, no impairment of goodwill is indicated, and our calculations indicates that the estimated fair value of this segment exceeds the carrying value, including goodwill, by a significant amount.

Derivatives and Hedging Activities

SFAS 133, as updated by 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 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 both Sequent and SouthStar.

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. Through Sequent and SouthStar, we use derivative instruments to reduce our exposure to the risk of changes in the prices 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 portfolio changes. This is primarily due to newly originated transactions and the effect of price changes. Sequent recognizes cash inflows and outflows associated with the settlement of these risk management activities in operating cash flows, and Sequent reports these settlements as receivables and payables separately from risk management activities in the balance sheet as energy marketing receivables and trade payables.

Under our risk management policy, we attempt to mitigate substantially all of our commodity price risk associated with Sequent s storage gas portfolio and lock-in the economic margin at the time we enter into gas purchase transactions for our stored gas. We purchase gas for storage when the current market price we pay for gas plus the cost to store the gas is less than the market price we could receive in the future by selling NYMEX futures contracts or other over-the-counter derivatives in the forward months, resulting in a positive net profit margin. We use contracts to sell gas at that future price to substantially lock-in the profit margin we will ultimately realize when the stored gas is actually sold. These contracts meet the definition of a derivative under SFAS 133.

The purchase, storage and sale of natural gas is 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.

Gas that we purchase and inject into storage is accounted for on an accrual basis, at the lower of average cost or market, as inventory in our consolidated balance sheets and 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 gas is lower than the carrying amount of our purchased gas inventory. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenues and cost of 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 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 gas 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. Based upon Sequent s storage positions at December 31, 2004, a $0.10 forward NYMEX change would result in $0.3 million impact to Sequent s EBIT.

Over time, gains or losses on the sale of gas 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 gas 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 this risk using the most effective methods to reduce or eliminate the impacts of these exposures. A significant 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 other comprehensive income (OCI) and are reclassified into earnings in the same period as the settlement of the underlying hedged item. Any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not perfectly 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. The remainder of SouthStar s derivative instruments does not meet the hedge criteria under SFAS 133. Therefore, changes in their fair value are recorded in earnings in the period of change.

Weather derivative contracts SouthStar routinely enters into weather derivative contracts for hedging purposes in order to preserve margins in the event of warmer-than-normal weather in the winter months. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of EITF 99-02, Accounting for Weather Derivatives . There were no weather derivative contracts outstanding as of December 31, 2004 and 2003.

Accounting for 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 (SFAS 5). 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 upon actual outcomes or changes in the facts or expectations surrounding each potential exposure.

Allowance for Doubtful Accounts

For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. Some of the more important factors that we use in the preparation of our allowance amounts are the customer status, the customer s aging balance and historical collection experience and trends. 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 which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions.

Accounting for Pension Benefits

We have a defined benefit pension plan for the benefit of substantially all full-time employees and qualified retirees. We use several statistical and other factors that attempt to anticipate future events and to calculate the expense and liability related to the plan. These factors include our assumptions about the discount rate, expected return on plan assets and rate of future compensation increases. In addition, our actuarial consultants use subjective factors such as withdrawal and mortality rates to estimate the projected benefit obligation. 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.

As of December 31, 2002, we recorded an additional minimum pension liability of $80 million, which resulted in an aftertax loss to other comprehensive income (OCI) of $49 million for 2002. At December 31, 2003, we reduced our minimum pension liability by approximately $14 million, which resulted in an aftertax gain to OCI of $8 million, reflecting our 2003 funding contributions to the plan and updated valuations for the projected benefit obligation and plan assets. At December 31, 2004 we increased our minimum pension liability by approximately $18 million, resulting in an aftertax loss to OCI of $7 million. Additionally, we have 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. 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.

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, and therefore the risks and uncertainties described below may not be the only ones we face. Additional risks and uncertainties that we are unaware of, or that we currently deem immaterial, also may become important factors that cause serious damage to our business in the future.

<u>Risks Related to the NUI Acquisition</u>

We may encounter difficulties integrating NUI into our business and may not fully attain or retain, or achieve within a reasonable time frame, expected strategic objectives, cost savings and other benefits of the acquisition.

We expect to realize strategic and other benefits as a result of our acquisition of NUI. Our ability to realize these benefits or successfully integrate NUI s businesses, however, is subject to certain risks and uncertainties, including:

- the costs of integrating NUI and upgrading and enhancing its operations may be higher than we expect and may require more resources, capital expenditures and management attention than anticipated;
- employees important to NUI s operations may decide not to continue employment with us;
- we may be required to allocate some of the cost savings achieved through the integration of NUI to our existing regulated utilities, which could prevent us from retaining some of the benefits achieved if the allocated cost savings result in rate reductions in future rate proceedings;
- we may be unable to maintain and enhance our relationship with NUI s existing customers and regulators;
- we may be unable to anticipate or manage risks that are unique to NUI s business, including those related to its workforce, customer demographics, regulatory environment, information systems and diverse geography;
- we may be unable to appropriately and timely adapt to both existing and changing economic, regulatory and competitive conditions; and
- the financial results of operations we acquired are subject to many of the same factors that have historically affected our financial condition and results of operations, including weather sensitivity, extensive federal, state and local regulation, increasing gas costs, competition and market risks and national, regional and local economic conditions.

Our failure to manage these risks, or other risks related to the acquisition that are not presently known to us, could prevent us from realizing the expected benefits of the acquisition and also may have a material adverse effect on our results of operations and financial condition following the transaction.

NUI has certain liabilities and obligations related to its pre-acquisition activities that may result in unanticipated costs and expenses to us.

NUI has been, and continues to be, the subject of various lawsuits, regulatory audits, investigations and settlements related to certain of its and its affiliates business practices prior to the date of the acquisition agreement. We will bear the costs of any liability, expense or obligation related to ongoing or new lawsuits, regulatory audits, investigations or claims related to these pre-acquisition activities. Additionally, management of these claims and liabilities may require a disproportionate amount of our management s time and attention. A failure to manage these risks could negatively affect our results of operations, our financial condition and our reputation in the industry and may reduce the anticipated benefits of the acquisition.

NUI has material weaknesses in its internal controls that may force us to incur unanticipated costs to resolve after closing.

NUI s external and internal auditors performed audits during its fiscal 2003 and 2004 years that identified material weaknesses in NUI s internal controls. Additional internal control issues and deficiencies were identified in the focused audit of NUI and its affiliates that was conducted at the request of the NJBPU. We have initiated our efforts to assess the systems of internal control related to NUI s business in order to comply with the requirements of SOX 404. At this time, however, we believe these operations continue to have material deficiencies in their internal controls that we will be required to address and resolve. We cannot make any assurance that our systems of internal and disclosure controls and procedures will be able to detect or prevent all errors or fraud or ensure that all material information regarding weaknesses in controls will be made known to management in the near term. We may incur significant additional costs to resolve these internal control and disclosure issues.

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, our distribution businesses are regulated by the SEC under the PUHCA, the Georgia Commission, the Tennessee Authority, the NJPBU, 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 the 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 upon 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 retain 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 s 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, 2004, 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 46% of our total operating margin for 2004. 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.

Our revenues, operating results and financial condition may fluctuate with the economy and its corresponding impact on our customers.

Our business is influenced by fluctuations in the economy. As a result, adverse changes in the economy can have negative effects on our revenues, operating results and financial condition. The level of economic and population growth in our regulated operations service territories, particularly new housing starts, directly affects our potential for growing our revenues.

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. See Critical Accounting Policies. 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.

We believe that sustained declines in equity markets and reductions in bond yields have had and may continue to 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 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 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 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.

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

Wholesale services 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 business 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 the 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, Virginia Natural Gas, Chattanooga Gas and shares profits it earns from the management of those assets with those customers and their customers. In addition, Sequent has asset management agreements with certain nonaffiliated customers. On April 1, 2005, Sequent plans to commence asset management responsibilities for Elizabethtown Gas, Florida Gas and Elkton Gas. The contract terms are currently being negotiated. Sequent s results could be significantly impacted in the event that these agreements are not renewed or are amended or renewed with less favorable terms.

Our profitability may decline if the counterparties to our transactions fail to perform in accordance with our agreements.

Wholesale services 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. Wholesale services 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 analysis 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 57% of Sequent s credit exposure is concentrated in 20 counterparties. Although most of this concentration is with counterparties that are either load-serving utilities or end-use customers and that have supplied some level of credit support, default by any of these counterparties in their obligations to pay amounts due Sequent could result in credit losses that would negatively impact our wholesale services segment.

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

The commodity, storage and transportation portfolios of wholesale services 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, 2004 had a 1-day holding period VaR of $0.1 million and 10-day holding period VaR of $0.2 million.

Our hedging procedures may not fully protect our sales and net income from volatility.

To lower our financial exposure related to commodity price fluctuations, wholesale services may enter into contracts to economically hedge the value of our energy assets and operations. As part of this strategy, we may utilize fixed-price, forward, physical purchase and sales contracts; futures; and financial swaps and option contracts traded in the over-the-counter markets or on exchanges. However, we do not always hedge against the entire marketplace volatility exposure of our energy assets or our positions. To the extent we have unhedged positions or our hedging procedures do not work as planned, fluctuating commodity prices could cause our net income to be volatile and could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Physical trading introduces price risk on any net open positions at the end of each trading day, as well as a risk of loss resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. Although we manage our business to limit net open positions related to our physical storage, open positions may exist on a short-term basis. The determination of our net open position as of any day requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Net open positions may result in an adverse impact on our financial condition or results of operations if market prices move in an unfavorable manner.

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 wholesale services 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. This can result in volatility in reported earnings from one period to the next that does not exist from an economic standpoint over the full life of the hedge and the hedged item.

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 an 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, 2004, the remediation program was approximately 78% complete. As of December 31, 2004, projected costs associated with the MGP sites were $56 million. For elements of the MGP program where we still cannot perform engineering cost estimates, considerable variability remains in available future cost estimates.

In addition, NUI is associated with as many as 6 former sites in New Jersey and 10 former sites in other states. 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 $31 million to $116 million. Costs have been estimated for only one of the New Jersey sites, for which current estimates range from $2 million to $14 million.

The success of our telecommunications business strategy may be adversely affected by uncertain market conditions.

The current strategy of our telecommunications business is based upon our ability to lease telecommunications conduit and dark fiber in the Atlanta, Georgia and Phoenix, Arizona metropolitan areas. The market for these services, like the telecommunications industry in general, is very competitive, rapidly changing and currently suffering from lack of market commitments. We cannot be certain that growth in demand for these services will occur as expected. If the market for these services fails to grow as anticipated or becomes saturated with competitors, including competitors using alternative technologies, our investment in the telecommunications business may be adversely affected.

Future acquisitions and expansions, if any, may affect our business by increasing the level of our indebtedness and contingent liabilities and creating integration difficulties.

From time to time, we will evaluate and acquire assets or businesses or enter into joint venture arrangements that we believe complement our existing businesses and related assets. As a result, the relative makeup of our business is subject to change. These acquisitions and joint ventures may require substantial capital or the incurrence of additional indebtedness. Further, acquired operations or joint ventures may not achieve levels of revenues, operating income or productivity comparable to those of our existing operations or may not otherwise perform as expected. Realization of the anticipated benefits of acquisitions or other transactions could take longer than expected. Acquisitions or joint ventures may also involve a number of risks, including:

- our inability to integrate operations, systems and procedures
- the assumption of unknown risks and liabilities
- diversion of management s attention and resources
- difficulty retaining and training acquired key personnel

Our ability to successfully make strategic acquisitions and investments will depend on: (1) the extent to which acquisitions and investment opportunities become available; (2) our success in bidding for the opportunities that do become available; (3) regulatory approval, if required, of the acquisitions on favorable terms; and (4) our access to capital and the terms upon which we obtain capital. If we are unable to make strategic investments and acquisitions, we may be unable to grow.

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

In order to maintain our historic growth, we must construct additions to our natural gas distribution system each year. 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. Our ability to finance the cost of constructing additions to our system depends on our ability to borrow funds or sell our common stock.

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, either during 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 that unusually cold or warm weather has 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 upon 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, which occurred in some prior years, 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 2005.

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.

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

Our gas supply depends upon 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.

Risks Related to Our Corporate and Financial Structure

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 these agreements 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 of our outstanding obligations in the event of a default on our part.

The indenture under which Atlanta Gas Light s outstanding Medium-Term notes were issued and the loan agreements for our bank lines of credit contain cross-default provisions which provide that we will be in default under the indenture or loan agreements in the event of certain defaults under any other indenture or loan agreement. 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 of 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 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
- decreases in the market price of and demand for natural gas
- adverse regulatory actions that affect our local gas distribution companies
- terrorist attacks on our facilities or our suppliers

Increases in our leverage could adversely affect our competitive position and financial condition.

An increase in our debt relative to our total capitalization could adversely affect us by

- increasing the cost of future debt financing
- limiting our ability to obtain additional financing, if we need it, for working capital, acquisitions, debt service requirements or other purposes
- making it more difficult for us to satisfy our existing financial obligations
- requiring us to dedicate a substantial portion of our cash flow from operations to payments on our debt, which would reduce funds available to us for operations, future business opportunities or other purposes

- prohibiting the payment of dividends on our common stock or adversely impacting our ability to pay such dividends at the current rate
- increasing our vulnerability to adverse economic and industry conditions
- limiting our flexibility in planning for, or reacting to, changes in our business and the industry in which we compete

Changing rating agency requirements could negatively affect our growth and business strategy, and a downgrade in our credit rating could negatively affect our ability to access capital.

S&P, Moody s and Fitch have recently implemented new requirements for various ratings levels. In order to maintain our current credit ratings in light of these or future new requirements, we may need to take steps or change our business plans in ways that may affect our growth and earnings per share. 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 P-2, A-2 and F-2 by S&P, Moody s and Fitch, respectively. If the rating agencies downgraded 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, 2004, if our credit rating had fallen below investment grade, we would have been required to provide collateral of approximately $20 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 depend on cash flow from our operations to pay dividends on our common stock.

We depend on dividends or other distributions of funds from our subsidiaries to pay dividends on our common stock. Payments of our dividends will depend on our subsidiaries earnings and other business considerations and may be subject to statutory or contractual obligations. Additionally, payment of dividends on our common stock is at the sole discretion of our Board of Directors.

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 assure you 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 our earnings that derive from transactions where we capture the difference between authorized returns and short-term borrowings.

Our tax rate may be increased and/or tax laws affecting us can change that may have an adverse impact on our cash flows and profitability.

The rates of federal, state and local taxes applicable to the industries in which we operate, which often fluctuate, could be increased by the respective taxing authorities. In addition, the tax laws, rules and regulations that affect our business could change. Any such increase or change could adversely impact our cash flows and profitability.

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.

Recent investigations and events involving the energy markets have resulted in an increased level of public and regulatory scrutiny in the energy industry and in the capital markets, resulting in increased regulation and new accounting standards.

As a result of the bankruptcy and adverse financial condition affecting several entities, particularly the bankruptcy filing by Enron, recently discovered accounting irregularities of various public companies and investigations by governmental authorities into energy trading activities, public companies, including particularly those in the energy industry, have been under an increased amount of public and regulatory scrutiny. Recently discovered practices and accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. New laws, such as the Sarbanes-Oxley Act of 2002, and regulations to address these concerns have been and continue to be adopted, and capital markets and rating agencies have increased their level of scrutiny. Costs related to increased scrutiny may have an adverse effect on our business, financial condition and access to capital markets. In addition, the FASB or the SEC could enact new accounting standards that could impact the way we are required to record revenues, assets and liabilities. These changes in accounting standards could lead to negative impacts on our reported earnings or increases in our liabilities.

QUANTITATIVE AND QUALITATIVE DISCLOSURE 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 the overall establishment of risk management policies and the monitoring of 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, and 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.

Commodity Price Risk

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, option 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, 2004 and 2003. We base the average values on monthly averages for the 12 months ended December 31, 2004 and 2003.

UNAUDITED	Asset			
	Average 12-Month Values		Value at:	
In millions	2004	2003	Dec. 31, 2004	Dec. 31, 2003
Natural gas contracts	$ 28	$ 14	$ 36	$ 13

UNAUDITED	Liability			
	Average 12-Month Values		Value at:	
In millions	2004	2003	Dec. 31, 2004	Dec. 31, 2003
Natural gas contracts	$ 21	$ 14	$ 19	$ 18

We employ a systematic approach to the evaluation and management of the risks associated with our contracts related to wholesale marketing and risk management, including VaR. 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. We use a 1-day and a 10-day holding period and a 95% confidence interval to evaluate our 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.

Our open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because we generally manage physical gas assets and economically protect our positions by hedging in the futures markets, our open exposure is generally minimal, permitting us to operate within relatively low VaR limits. We employ daily risk testing, using both VaR and stress testing, to evaluate the risks of our open positions.

Our management actively monitors open commodity positions and the resulting VaR. We continue to maintain a relatively matched book, where our 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, our portfolio of positions for the 12 months ended December 31, 2004 and 2003 had the following 1-day and 10-day holding period VaRs:

UNAUDITED 2004		
In millions	1-day	10-day
Period end	$ 0.1	$ 0.2
12-month average	0.1	0.3
High	0.4	1.3
Low (1)	0.0	0.0

UNAUDITED 2003		
In millions	1-day	10-day
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.

Energy Investments 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. This policy also establishes VaR limits of $0.5 million on a 1-day holding period and $0.7 million on a 10-day holding period. In June 2004, the SouthStar risk management committee approved replacing the 20-day VaR limit with a 10-day VaR limit. The 10-day VaR limit was determined to be a more appropriate industry standard, and thus was adopted by SouthStar. A 95% confidence interval is used to evaluate VaR exposure. The maximum VaR experienced during 2004 was less than $0.2 million for the 1-day holding period and $0.5 million for the 10-day holding period.

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 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-upon notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the Senior Notes due 2011, and $75 million of the $150 million principal amount of Trust Preferred Securities due in 2041. In March 2004, we adjusted our fixed to variable-rate debt obligations and terminated an interest rate swap on $100 million of the $225 million principal amount of Senior Notes due 2013. More information about our interest swaps are shown in the following table:

UNAUDITED		Market Value of Interest Rate Swap Derivatives			
Dollars in millions				Market Value as of:	
Notional Amount	Fixed-Rate	Effective variable rate (1)	Maturity	Dec.31, 2004	Dec. 31, 2003
$75	8.0%	3.6%	May 15, 2041	$3	$3
$100	7.1%	5.2%		(2)	(2)

			January 14, 2011		
$100	4.5%	-	April 15, 2013	-	(5)

(1) As of December 31, 2004

Credit Risk

Distribution Operations Atlanta Gas Light has a concentration of credit risk as it bills 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 2004, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 46% of our operating margin and 61% 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, 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 the adequacy of credit support coverage, credit rating profiles of credit support providers and payment status of each Marketer on a monthly basis. 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.

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 we are engaged in more than one outstanding derivative transaction with the same counterparty and we also have a legally enforceable netting agreement with that counterparty, the net mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of our credit risk. Sequent also uses other netting agreements with certain counterparties with whom we conduct 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. We conduct credit evaluations and obtain appropriate internal approvals for our 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, we require 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, 2004, Sequent s top 20 counterparties represented approximately 57% of the total counterparty exposure of $328 million, derived by adding the top 20 counterparties exposures divided by the total of Sequent s counterparties exposures.

As of December 31, 2004, Sequent s counterparties, or the counterparties guarantors, had a weighted average S&P equivalent credit rating of A- compared to BBB at December 31, 2003. 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, 2004 and 2003:

UNAUDITED

Gross receivables	As of:		
In millions	Dec. 31, 2004	Dec. 31, 2003	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	$ 378	$ 288	$ 90
Counterparty is non-investment grade	36	13	23
Counterparty has no external rating	78	9	69
Receivables without netting agreements in place:			
Counterparty is investment grade	16	15	1
Counterparty is non-investment grade	6	-	6
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$ 514	$ 325	$ 189

UNAUDITED

Gross payables	As of:		
In millions	Dec. 31, 2004	Dec. 31, 2003	Change
Payables with netting agreements in place:			
Counterparty is investment grade	$ 291	$ 206	$ 85
Counterparty is non-investment grade	45	31	14
Counterparty has no external rating	139	45	94
Payables without netting agreements in place:			
Counterparty is investment grade	40	29	11
Counterparty is non-investment grade	6	3	3
Counterparty has no external rating	-	15	(15)
Amount recorded on balance sheet	$ 521	$ 329	$ 192

Energy Investments SouthStar has established the following credit guidelines and risk management practices for each customer type:

- SouthStar scores firm residential and small commercial customers using a national reporting agency and enrolls, without security, only those customers that meet or exceed SouthStar s credit threshold.
- SouthStar investigates potential interruptible and large commercial customers through reference checks, review of publicly available financial statements and review of commercially available credit reports.
- SouthStar assigns physical wholesale counterparties an internal credit rating and credit limit prior to entering into a physical transaction based on their Moody s, S&P and Fitch rating, commercially available credit reports and audited financial statements.

Item 9.01. Financial Statements and Exhibits.

(c) Exhibits

Exhibit No.	**Description**
99.1	AGL Resources Press Release announcing its financial results and other information.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

	AGL RESOURCES INC.
	(Registrant)
Date: January 28, 2005	/s/ Richard T. O Brien
	Executive Vice President and Chief Financial Officer

Exhibit Index

Exhibit No.	Description
99.1	AGL Resources Press Release announcing its financial results and other information.