AGL RESOURCES INC
Form 8-K
January 28, 2004

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, 2004

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

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

Ten Peachtree Place Atlanta, Georgia 30309
(Address and zip code of principle executive offices) (Zip Code)

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

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

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Item 12. Results of Operations and Financial Condition

On January 28, 2004, AGL Resources Inc. announced its financial results for the three months and twelve months ended December 31, 2003 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 9. Regulation FD Disclosure

On January 28, 2003 at 3:30 p.m. AGL Resources plans to hold a fourth quarter 2003 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, 2003.

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The summary discussions were derived from unaudited financial statements.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Unless the context requires otherwise, references to we, us, our or the company are intended to mean consolidated AGL Resources Inc. and its subsidiaries (AGL Resources). Our reports, filings and other public announcements often include statements reflecting assumptions, expectations, projections, intentions or beliefs about future events. These statements, which may relate to such matters as future earnings, growth, supply and demand, costs, subsidiary performance, new technologies and strategic initiatives, are forward-looking statements within the meaning of the federal securities laws. These statements do not relate strictly to historical or current facts, and you can identify certain of these statements, but not necessarily all, by the use of the words anticipate, assume, indicate, estimate, believe, predict, forecast, rely, expect, continue, grow and other words of similar meaning. Although we believe that t expectations and assumptions reflected in these statements are reasonable in view of the information currently available, we cannot assure you that these expectations will prove to be correct. These forward-looking statements involve a number of risks and uncertainties. Actual results may differ materially from the results discussed in the forward-looking statements. For additional information on the risks associated with our business, see our Risk Factors contained in this Annual Report.

Introduction

We are an energy services holding company, headquartered in Atlanta, Georgia, whose principal business is the distribution of natural gas in Georgia, Virginia and Tennessee. Our principal executive offices are located at Ten Peachtree Place, Atlanta, Georgia 30309. The telephone number at that address is (404) 584-4000. As shown in the following chart, we conduct substantially all our operations through our subsidiaries or affiliated companies which we manage as three operating segments--distribution operations, wholesale services and energy investments--and one nonoperating segment, corporate.

Distribution operations includes three utilities that together serve approximately 1.8 million end-use customers, of which approximately 83% are located in Georgia, 14% are located in Virginia and 3% are located in Tennessee. Our wholesale services segment includes our nonutility business engaged in natural gas asset management and optimization, producer services and wholesale marketing, and risk management activities. Our energy investments segment includes our nonutility businesses engaged in operating telecommunications conduit and fiber infrastructure within select metropolitan areas and retail natural gas and propane marketing. Our business strategy is to effectively operate and grow our gas distribution operations, optimize returns on our assets, and selectively grow our portfolio of closely related, unregulated businesses while remaining focused on risk management and earnings visibility.

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Summary

Results of Operations

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Our net income increased $24.9 million or 24% over 2002 with basic and diluted earnings per share of $2.03 and $2.01 as compared to $1.84 and $1.82 in 2002 for an increase of $0.19 or 10%.

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The increase in earnings is primarily from increased earnings before interest and taxes (EBIT) of $51.1 million and reduced interest expense of $10.4 million or 12% offset by an increase in income tax of $28.8 due to increased earnings before income taxes of $61.5 million and a higher projected effective tax rate for 2003.

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Improved earnings from distribution operations, SouthStar Energy Services, LLC (SouthStar) and Sequent Energy Management, LP (Sequent) primarily drove the increase in EBIT:

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The distribution operations segment contributed EBIT of $246.8 million, compared to a 2002 EBIT contribution of $224.4 million. Excluding a net $13.5 million pretax gain on the sale of our former corporate headquarter at our Caroline Street campus and a charitable donation, the distribution operations segment EBIT for 2003 was $233.3 million, a 4% increase over 2002. The increase was primarily due to higher operating margins driven by higher customer usage, an increase in the number of connected customers primarily from Virginia Natural Gas Company, Inc. (VNG) and an increase in pipeline replacement revenue at Atlanta Gas Light Company (AGLC). Total operating expenses, excluding cost of gas, for 2003 were $366.7 million, compared to $362.5 million in 2002. The increase in operating expenses reflects higher overhead costs, including an increase in building lease expenses.

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The wholesale services segment contributed $19.6 million in EBIT for the year compared to $9.1 million in 2002, a 115% increase. The earnings improvement resulted primarily from increased activity related to optimization of transportation and storage assets and increased commodity margins, particularly in the first quarter of 2003 when Sequent sold substantially all its inventory during the quarter. Sequent s results also were impacted by Emerging Issues Task Force (EITF) Issue No. 02-03, Issues Involved in Accounting for Contracts under EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities (EITF 02-03), which rescinded EITF 98-10 and resulted in inventory, which was previously recorded on a mark-to-market basis, to be recorded on an accrual basis. This resulted in a change in accounting principle for a cumulative effect of ($7.8) million or ($0.12) basic earnings per common share.

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The energy investments segment contributed $43.1 million in EBIT in 2003, compared to $23.6 million in 2002, an 83% increase. SouthStar accounted for the majority of the segment s improved results. SouthStar s improvement resulted primarily from higher operating margins and reduced bad debt and operating expenses, as well as our increased ownership percentage (from 50% to 70%) in the joint venture. Results at SouthStar also reflect the settlement of the disproportionate sharing of earnings with Piedmont Natural Gas Company (Piedmont) in the fourth quarter. The agreement resulted in an our recognition of an additional $5.9 million of equity earning for the 12 months ended December 31, 2003, and resolves all outstanding issues related to disproportionate sharing between the two partners in SouthStar.

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The sale of the Caroline Street campus increased our basic earnings per share from 2002 by an additional $0.08. Excluding the gain, our basic earnings per share for 2003 was $1.95, an increase of $0.11 or 6% over 2002.

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Our operating cash flow in 2003 was $122.1 million, a decrease of $163.4 million from 2002. This decrease was primarily the result of increased spending for injection of natural gas inventories of approximately 11 Bcf. The weighted average cost of our inventory was approximately 30% higher than last year. In addition, we made $21.5 million in pension contributions this year as a result of our continued efforts to fully fund our pension liability. The increased spending on inventories and pension funding were somewhat offset by increased net income of $24.9 million and cash received from SouthStar of $40.0 million.

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Liquidity and Capital Resources

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We ended 2003 with a stronger balance sheet, as measured by debt to-total capitalization and improved liquidity, as measured by cash and availability under our credit facility. Primarily through a $136.7 million equity offering of 6.4 million shares and adding $127.9 million of earnings, we increased common equity from $710.1 million at December 31, 2002 to $945.3 million at December 31, 2003.

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We also reduced total debt outstanding from $1,412.8 million at December 31, 2002 to $1,339.5 million at December 31, 2003. Liquidity improved from $252.5 million at 12/31/02 to $516.5 million at December 31, 2003. As a result, our debt-to-capitalization ratio decreased from 66.5% at December 31, 2002 to 58.6% at December 31, 2003. Our balance sheet and cash flow improvements enabled us to raise our shareholder dividend. We now pay an indicated annualized dividend of $1.12 per share, a 4% increase over the previous $1.08 per share.

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We currently have an active shelf registration statement for up to $750 million of various capital securities, with remaining capacity of approximately $383 million. On September 23, 2003, we filed a second shelf registration with the Securities and Exchange Commission (SEC) for authority to increase our capacity to $1.0 billion of various capital securities.

Other Activities

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At the beginning of 2003, we announced our purchase of Dynegy Inc s (Dynegy) 20% ownership interest in SouthStar for $20 million. This increase in ownership provided an additional $9.0 million of other income in 2003.

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We formed Pivotal Energy Development (Pivotal) to identify opportunities to extend our natural gas delivery capabilities while improving system reliability. Two such opportunities have been identified to date: a propane-air plant in Virginia, which is currently in the permitting stages; and a pipeline project between Atlanta and Macon, Georgia to enhance access to a liquefied natural gas (LNG) facility we have there. The construction phase of the Macon project is planned for 2005, pending redeployment of certain existing interstate pipeline infrastructure.

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We closed on the sale of our Caroline Street campus for net proceeds of $22.7 million, resulting in a gain before income taxes of $15.9 million. We contributed $8.0 million of these proceeds to the AGL Resources Private Foundation, Inc., a non-profit foundation, which makes charitable contributions to qualified tax-exempt organizations. After the contribution and net of taxes, the sale increased our basic earnings per common share by an additional $0.08 and our diluted earnings per common share by an additional $0.08. The gain before income taxes of $15.9 million was recorded as operating income (loss) in two of our segments. A gain of $21.5 million on the sale of the land was recorded in our distribution operations segment, and a write-off of ($5.6) million on the buildings and their contents was recorded in our corporate segment.

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Results of Operations

Our management evaluates segment financial performance based on EBIT, which includes the effects of corporate expense allocations. Items that are not included in EBIT are financing costs, including interest and debt expense, income taxes and the cumulative effect of changes in accounting principles. We evaluate each of these items on a consolidated level. We believe EBIT is a useful measurement of our performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the efficiency of those operations.

Operating margin is a non-GAAP measure of income, calculated as revenues minus cost of gas, excluding operation and maintenance expense, depreciation and amortization, taxes other than income taxes and the gain on sale of our Caroline Street campus. These items are included in our calculation of operating income. We believe operating margin is a better indicator than revenues of the top line contribution resulting from customer growth, since cost of gas is generally passed directly to our customers.

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 accounting principles generally accepted in the United States of America (GAAP). In addition, our operating margin or EBIT may not be comparable to a similarly titled measure of another company. The following is a reconciliation of our operating margin to operating income and a reconciliation of EBIT to earnings before income taxes and net income, on a consolidated basis for 2003, 2002 and fiscal 2001.

(Unaudited)

In millions, except per share amounts	**Calendar 2003**	Calendar 2002	Fiscal 2001	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	**$983.7**	$877.2	$946.2	$106.5	($69.0)
Cost of gas	**339.4**	268.2	327.3	71.2	(59.1)
Operating margin	**644.3**	609.0	618.9	35.3	(9.9)
Operating expenses					
Operation and maintenance	**282.7**	274.1	267.2	8.6	6.9

Depreciation and amortization	**91.4**	89.1	100.0	2.3	(10.9)
Taxes other than income taxes	**27.8**	29.3	32.8	(1.5)	(3.5)
Total operating expenses	**401.9**	392.5	400.0	9.4	(7.5)
Gain on sale of Caroline Street campus	**15.9**	-	-	15.9	-
Operating income	**258.3**	216.5	218.9	41.8	(2.4)
Other income	**39.8**	30.5	17.3	9.3	13.2
EBIT	**298.1**	247.0	236.2	51.1	10.8
Interest expense	**75.6**	86.0	97.4	(10.4)	(11.4)
Earnings before income taxes	**222.5**	161.0	138.8	61.5	22.2
Income taxes	**86.8**	58.0	49.9	28.8	8.1
Income before cumulative effect of change in accounting principle	**135.7**	103.0	88.9	32.7	14.1
Cumulative effect of change in accounting principle	**(7.8)**	-	-	(7.8)	-
Net income	**127.9**	103.0	88.9	24.9	14.1
Basic earnings per common share					
Income before cumulative effect of change in accounting principle	**$2.15**	$1.84	$1.63	$0.31	$0.21
Cumulative effect of change in accounting principle	**(0.12)**	-	-	(0.12)	-
Basic earnings per common share	**$2.03**	$1.84	$1.63	$0.19	$0.21
Diluted earnings per common share					
Income before cumulative effect of change in accounting principle	**$2.13**	$1.82	$1.62	$0.31	$0.20
Cumulative effect of change in accounting principle	**(0.12)**	-	-	(0.12)	-
Diluted earnings per common share	**$2.01**	$1.82	$1.62	$0.19	$0.20
Weighted average number of common shares outstanding					
Basic	**63.1**	56.1	54.5	7.0	1.6
Diluted	**63.7**	56.6	54.9	7.1	1.7

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2003 compared to 2002 Net income increased $24.9 million from 2002, reflecting higher earnings at each operating segment. EBIT from distribution operations (excluding the net gain on the sale of Caroline Street of $13.5 million, discussed below) increased 4% ($233.3 million vs. $224.4 million) due to higher operating margins, an increase in the number of connected customers and increased pipeline replacement revenue in 2003. The wholesale services segment contributed $19.6 million in EBIT compared to $9.1 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.

Our energy investments segment contributed $43.1 million in EBIT compared to $23.6 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 the disproportionate sharing issue with Piedmont. Our corporate segment s expenses decreased primarily as a result of favorable interest expense and lower average debt balances.

The following table shows the impact of the sale of our Caroline Street campus and the related donation to the private foundation on our distribution operations and corporate segments.

(Unaudited)

In millions	**Distribution Operations**	**Corporate**	**Consolidated**
Gain (loss) on sale of Caroline Street campus	$21.5	($5.6)	$15.9
Donation to private foundation	(8.0)	-	(8.0)
EBIT impact	13.5	(5.6)	7.9
Income taxes			(3.1)
Net income impact			$4.8

2002 compared to fiscal 2001 Net income for 2002 increased $14.1 million from fiscal 2001, reflecting continued operational efficiencies in distribution operations, greater contributions from wholesale services due to significant price volatility, greater contributions from energy investments due to improved business operations and lower interest expense, partially offset by the gain on the sale of Utilipro Inc. (Utilipro) in 2001.

EBIT by Segment

Our distribution operations segment contributed approximately 80% of our operating EBIT in 2003, down from approximately 90% in 2002 and 2001. The decrease was a result of significantly higher EBIT from both wholesale services and energy investments. The following table summarizes EBIT for each of our business segments.

(Unaudited)

In millions	**Fiscal 2001**

	Calendar 2003	Calendar 2002		2003 vs. 2002	2002 vs. 2001
Distribution operations	$246.8	$224.4	$213.2	$22.4	$11.2
Wholesale services	19.6	9.1	3.1	10.5	6.0
Energy investments	43.1	23.6	21.3	19.5	2.3
Corporate	(11.4)	(10.1)	(1.4)	(1.3)	(8.7)
Consolidated EBIT	$298.1	$247.0	$236.2	$51.1	$10.8

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Income Taxes

(Unaudited)

Dollars in millions	Calendar 2003	Calendar 2002	Fiscal 2001	2003 vs. 2002	2002 vs. 2001
Earnings before income taxes	$222.5	$161.0	$138.8	$61.5	$22.2
Income tax expense	86.8	58.0	49.9	28.8	8.1
Effective tax rate	39.0%	36.0%	36.0%	3.0%	-

2003 compared to 2002 The increase in income tax expense of $28.8 million for 2003 compared to 2002 was due primarily to the increase in earnings before income taxes of $61.5 million and an increase in our effective tax rate from 36.0% in 2002 to 39.0% 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 book and tax basis of some of our assets.

2002 compared to fiscal 2001 The increase in income tax expense of $8.1 million in 2002 as compared to fiscal 2001 was due to the increase in earnings before income taxes of $22.2 million while the effective tax rate was unchanged.

Interest Expense

(Unaudited)

Dollars in millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Total interest expense	$75.6	$86.0	$97.4	($10.4)	($11.4)
Average debt outstanding (1)	1,255.3	1,411.9	1,376.1	(156.6)	35.8
Average rate	6.0%	6.1%	7.1%	(0.1%)	(1.0%)

(1)

Daily average of all outstanding debt including our Trust Preferred Securities.

2003 compared to 2002 The decrease in interest expense of $10.4 million for 2003 as compared to 2002 was a result of lower average debt balances due primarily to the proceeds generated from our equity offering; repayment of Medium-Term notes, which had higher rates than our bond issuance in July; the benefits of our interest rate swaps; and lower interest rates on commercial paper borrowings.

2002 compared to fiscal 2001 The decrease in interest expense of $11.4 million for 2002 as compared to fiscal 2001 was a result of lower interest rates on commercial paper and the effect of favorable fixed to floating interest rate swaps, which was offset by slightly higher average debt balances due to increases in working capital needs.

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Distribution Operations

Distribution operations includes the results of operations and financial condition of our three natural gas local distribution utility companies: Atlanta Gas Light Company (AGLC), Virginia Natural Gas, Inc. (VNG) and Chattanooga Gas Company (CGC). Distribution operations   revenues contributed 95.1% of our consolidated revenues for 2003, 97.1% for 2002, 96.8% for the transition period and 97.2% for fiscal 2001. Each utility operates subject to regulations provided by the state regulatory agencies in its service territories.

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AGLC is a natural gas local distribution utility with distribution systems and related facilities throughout Georgia. AGLC has approximately 6 billion cubic feet, or Bcf, of LNG storage capacity in three LNG plants to supplement the supply of natural gas during peak usage periods. Pursuant to the Georgia Natural Gas Competition and Deregulation Act, AGLC is designated as an electing distribution company, which means that AGLC is required to offer LNG peaking services to marketers at rates and on terms approved by the Georgia Public Service Commission (GPSC).

Performance-Based Rates AGLC operates under a three-year performance-based rate (PBR) plan that became effective May 1, 2002, with an allowed return on equity of 11%. The PBR plan also establishes an earnings band based on a return on equity of 10% to 12%, with three-quarters of any earnings above a 12% return on equity shared with Georgia customers and one-quarter retained by AGLC.

In the last year of the PBR plan (May 2004 April 2005), the GPSC staff and AGLC will review the operation of the plan and review AGLC s revenue requirement to determine whether base rates should be reset upon the initial plan s expiration. The GPSC will then determine whether the plan should be discontinued, extended or otherwise modified. As part of any hearing procedure, AGLC will file a cost of service study in accordance with the GPSC s minimum filing requirements as well as supporting testimony. AGLC plans to file the required cost of service study in 2004, the precise timing of which is subject to discussions with the GPSC staff.

Straight-Fixed-Variable Rates AGLC's revenue is recognized under a straight-fixed-variable rate design, where AGLC charges rates to its customers based primarily on a fixed charge. This minimizes the seasonality of both revenues and expenses since the fixed charge is not volumetric and therefore not 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 AGLC s revenues, since generally more customers will be connected in periods of colder weather than in periods of warmer weather.

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VNG is a natural gas local distribution utility with distribution systems and related facilities serving the region of southeastern Virginia. VNG 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. VNG 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.

Weather normalization adjustment On September 27, 2002, the Virginia State Corporation Commission (VSCC) approved a weather normalization adjustment (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. Under the terms of the program, if VNG requests to continue the WNA program after the two-year experiment, it is required to file a fully adjusted cost of service study along with the same schedules as would be required for a general rate case. It is possible the VSCC may require a general rate case prior to extending the WNA program. VNG plans to request an extension of the WNA program in 2004**.**

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CGC is a natural gas local distribution utility with distribution systems and related facilities serving the Chattanooga and Cleveland areas of Tennessee. CGC has approximately 1.2 Bcf of LNG storage capacity in its LNG plant. Included in the base rates charged by CGC is a WNA factor that allows for revenue to be recognized based on a weather normalization factor derived from average temperatures over a 30-year period, which offsets the impact of unusually cold or warm weather on our operating income.

On January 26, 2004, CGC filed a request for a total rate increase of $4.5 million with the Tennessee Regulatory Authority (TRA), as rates have not increased since 1995. If approved, new rates would be effective March 1, 2004, subject to a TRA suspension for hearing. The rate plan was filed to cover CGC s rising cost of providing natural gas to its customers.

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Pivotal Energy Development In 2003, we announced the formation of Pivotal to coordinate, among our related companies, the development, construction or acquisition of assets in the Southeast and Mid-Atlantic regions that extend our natural gas capabilities and improve system reliability, while enhancing service to our customers in those areas.

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Virginia In 2004, Pivotal intends to complete the construction of a propane facility in the VNG service territory. A filing with the VSCC was made in November 2003 seeking approval for an affiliate contract between Pivotal and VNG. Under this proposed contract, Pivotal would provide VNG with 28,800 dekatherms of propane air per day on a 10-day-per-year basis to serve its peaking needs. Construction of the facility by Pivotal is contingent upon the VSCC s approval of the contract between Pivotal and VNG, and we expect their decision during the first quarter of 2004.

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Georgia Pivotal is currently evaluating a pipeline project between Atlanta and Macon to enhance access to our LNG facility and lower the cost of gas to our customers. The construction phase of the Macon project is planed for 2005, pending redeployment of certain existing interstate pipeline infrastructure.

Gas Supply Gas supply or capacity planning is conducted for each of our regulated jurisdictions. The basic premise of a capacity plan is to evaluate the costs of alternative asset arrays meeting firm customer demand for natural gas under varying weather conditions that exist in our service territories. On an annual basis the array of assets for each utility must have adequate interstate transportation, underground storage and LNG capacity to meet firm customer demand if the weather is colder than normal, and must be flexible enough to adjust for firm customer demand in a winter that is warmer than normal.

Rates and Regulation The GPSC regulates AGLC; the VSCC regulates VNG; and the TRA regulates CGC 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, pay preferred dividends 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 filing. The following tables depict the currently authorized and estimated rates of return for AGLC, VNG and CGC:

	Authorized return on rate base	Authorized return on equity	Estimated 2003 jurisdictional return on equity
AGLC	9.16%	10.0 12.0%	11.17%
VNG	9.24%	10.0 11.4%	11.07%
CGC	9.08%	11.06%	8.05%

State Activity Since 1998, a number of federal and state proceedings have addressed the role of AGLC to administer and assign interstate assets to Marketers pursuant to the provisions of the Natural Gas Competition and Deregulation Act of Georgia. Most recently, AGLC entered into a stipulation with the GPSC staff, industrial customers, the Governor s Office of Consumer Affairs and all but one of the Marketers using its systems regarding the assignment of its interstate capacity assets. A hearing to approve the stipulation was held, and on July 24, 2003, the GPSC unanimously approved the stipulation. Under the approved terms, AGLC is authorized to offer two additional sales services pursuant to GPSC-approved tariffs, and acquire and continue managing the interstate transportation and storage contracts that underlie the sales services provided to Marketers on its distribution system under GPSC-approved tariffs.

Federal Activity The Pipeline Safety Improvement Act of 2002, enacted on December 17, 2002, required the Office of Pipeline Safety (OPS) to establish new regulations for the inspection of transmission pipelines by December 2003. The OPS issued its final rules in December 2003. The OPS rules will require our three utility subsidiaries to inspect and take remedial action on approximately 350 miles of our large-diameter pipelines with an initial estimated cost over a 10-year period of $22 million in maintenance expense. We believe that since the efforts that require these expenditures are federally mandated the costs will be recoverable from customers.

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On January 14, 2004, VNG filed a complaint with the Federal Energy Regulatory Commission against Columbia Gas Transmission (Columbia), a subsidiary of NiSource Inc. Among other things, the complaint alleges that during last winter s heating season, beginning in January 2003, VNG experienced a number of critical service problems with Columbia that interrupted deliveries of natural gas to some industrial customers and increased prices paid by VNG s customers. VNG is seeking approximately $37 million in damages, the majority of which would be distributed to VNG s customers.

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 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 comfort of natural gas heating versus electric heating. 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. We experienced consistent growth among the residential and small commercial customer classes as a result of our success in these markets. We believe that our consumers continuing preference for natural gas allows us to maintain a strong market presence. However, our customers demand for natural gas and the level of business of natural gas assets could be affected by numerous factors, including

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changes in the availability or price of natural gas and other forms of energy

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general economic conditions

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energy conservation

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legislation and regulations

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the capability to convert from natural gas to alternative fuels

o

weather

Customer profile Distribution operations primarily serves residential customers, as shown in the following table:

	AGLC	VNG	CGC
Residential	91%	92%	86%
Commercial and industrial	9	8	14
Total	100%	100%	100%

In 2003, our net customer growth was approximately 1%. While we experienced positive net growth, it has been limited due to the number of customers who choose to leave our systems. We expect our net customer growth to improve in the future through our efforts in:

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New business Applying a strategy to attain residential customers with 3 or more appliances, or burner tips, and multifamily complexes. We continue to seek high value commercial customers that use natural gas for purposes other than space heating and customers with 2 or more burner tips.

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Retention Gas partnerships with retailers, HVAC dealers, plumbers, appliance vendors, realtors and marketers. In addition, we are working on consumer advocacy with campaigns for at risk groups.

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Results of Operations The results of operations for distribution operations are as follows:

(Unaudited)

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	$935.9	$852.4	$919.6	$83.5	($67.2)
Cost of sales	337.3	267.4	321.9	69.9	(54.5)
Operating margin	598.6	585.0	597.7	13.6	(12.7)
Operation and maintenance expenses	261.3	255.3	268.0	6.0	(12.7)
Depreciation and amortization	80.9	82.0	90.4	(1.1)	(8.4)
Taxes other than income	24.5	25.2	28.5	(0.7)	(3.3)
Total operating expenses	366.7	362.5	386.9	4.2	(24.4)
Gain on sale of Caroline Street campus	21.5	-	-	21.5	-
Operating income	253.4	222.5	210.8	30.9	11.7
Donation to private foundation	(8.0)	-	-	(8.0)	-
Other income	1.4	1.9	2.4	(0.5)	(0.5)
Total other (loss) income	(6.6)	1.9	2.4	(8.5)	(0.5)
EBIT	$246.8	$224.4	$213.2	$22.4	$11.2

Metrics	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Average end-use customers (in thousands)	1,838	1,824	1,829	0.8%	(0.3%)
Operation and maintenance expenses per customer	$142	$140	$147	1.4	(4.8)
EBIT per customer (1)	$127	$123	$117	3.3	5.1
Customers per employee	1,551	1,523	1,238	1.8	23.0
Throughput (in millions of dekatherms)	299	306	325	(2.3)	(5.8)
Heating degree days (2):					
Georgia	2,654	2,812	3,072	(5.6)	(8.4)

Virginia	3,264	3,030	3,659	7.7	(17.1)
Tennessee	3,168	3,052	3,435	3.8	(11.1)

(1)

2003 EBIT per customer excludes the gain on the sale of our Caroline Street campus.

(2)

We measure the effects of weather on our businesses using degree days. The measure of degree days for a given day is the difference between the average daily actual temperature and the 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.

2003 compared to 2002 EBIT increased $22.4 million for 2003 as compared to 2002, primarily as a result of the gain of $21.5 million on the sale of the land from our Caroline Street campus, offset by the $8.0 million donation to AGL Resources Private Foundation, Inc. Excluding the gain and donation, EBIT increased $8.9 million from improved operations as a result of increased operating margin, partly offset by increased operating expenses.

Operating margin increased $13.6 million from 2002, primarily from an increase of $13.8 million from increased number of customers and a higher usage per degree day of which the largest increase was at VNG or approximately $12.0 million. Pipeline replacement program (PRP) rider revenues increased $2.3 million resulting from recovery of prior-year program expenses. Carrying costs charged to Marketers for gas stored underground also contributed $0.7 million due to higher storage volumes**.** Offsetting the increases was a reduction in AGLC s rates as compared to prior year of $3.3 million for the first four months of 2003 due to the PBR settlement agreement with the GPSC effective May 1, 2002. CGC s operating margin for 2003 were not materially different from 2002.

Operating expenses increased $4.2 million from 2002 due primarily to a $2.0 million increase in corporate allocated cost related to an increase in corporate building lease costs and higher general business insurance premiums. Bad debt expenses increased $2.2 million, primarily as a result of colder-than-normal weather and higher natural gas prices. Additional increases in operating expenses were attributed to a $1.2 million VNG regulatory asset write-off in 2003. These increases in operating expenses were partially offset by a $1.1 million decrease in depreciation expenses due to lower depreciation rates at AGLC for the first four months of 2003 as a result of the PBR settlement agreement with the GPSC.

2002 compared to fiscal 2001 The increase in EBIT of $11.2 million for 2002 compared to fiscal 2001 was primarily due to decreases in operating expenses of $24.4 million, which were partially offset by decreases in operating margin of $12.7 million.

Operating margin decreased $12.7 million primarily due to

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$11.3 million decrease in VNG s operating margin, resulting from the impact of warmer-than-normal winter weather of $12.4 million, partially offset by a $1.1 million increase in customers and the positive impact of an experimental WNA program that went into effect for the billing cycle beginning November 2002.

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CGC s operating margin decreased $1.2 million primarily due to lower use per customer.

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$0.1 million decrease in AGLC s operating margin, primarily due to a $6.7 decrease in AGLC rates as a result of the PBR settlement with the GPSC, a decrease of $4.3 million as a result of a decline in number of customers due to fewer end-use customers connecting to our system. Additional decreases to AGLC margin were a 2001 $2.7 million one-time adjustment to cost of sales as a result of inventory cost for natural gas stored underground. These decreases were offset by an $11.0 million increase in AGLC's PRP rider revenues, resulting from recovery of prior-year program expenses, and an increase in carrying costs charged to marketers for gas stored underground which contributed an additional $3.0 million.

Operating expenses decreased $24.4 million primarily due to

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$12.7 million decrease in operating and maintenance expenses related to reductions in payroll and contract costs as a result of implementing cost efficiencies.

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$6.0 million decrease in bad debt expenses as a result of higher-than-normal bad debt expense in fiscal 2001 as a result of colder-than-normal weather and higher-than-normal gas prices, resulting in higher customer bills during the 2001 heating season.

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$5.2 million decrease in goodwill amortization from 2001 as a result of the adoption of Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets (SFAS 142), effective October 1, 2001.

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Depreciation expense decreased $3.0 million in 2002 as compared to fiscal 2001, due to a decrease of $5.6 million caused by a decline in average depreciation rates (from 3.0% to 2.6%) as a result of AGLC s PBR settlement with the GPSC effective May 1, 2002, partially offset by an increase in depreciation expenses of $3.3 million due to higher property, plant and equipment balances.

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Wholesale Services

Wholesale services includes the results of operations and financial condition of Sequent, our subsidiary involved in asset optimization, producer services, and wholesale marketing and risk management. 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.

Asset management transactions Our asset management customers, which include our affiliated local distribution companies (LDCs), nonaffiliated utilities and municipals and industrial customers, must contract for transportation and storage services to meet their peak day demands. These customers typically contract for these services on a 365-day basis even though they may only need 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 off-peak periods. We capture margin by optimizing the purchase, transportation, storage and sale of natural gas, and typically either share profits with customers or pay a fee for using utility assets.

Regulatory agreements We have reached the following agreements with state regulatory commissions to clarify Sequent s role as asset manager for our regulated utilities. Failure to renew these agreements would have a significant impact on Sequent s EBIT.

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In November 2000, the VSCC approved an asset management agreement that provides for a sharing of profits between Sequent and VNG's customers. This agreement expires in October 2005, unless Sequent, VNG and the VSCC agree to extend the contract.

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Various Georgia statutes require Sequent, as asset manager for AGLC, 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 AGLC assets other than capacity release, to be shared equally with the USF.

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In June 2003, CGC s tariff was amended effective January 1, 2003 to require all net margin earned by Sequent for transactions involving CGC assets to be shared equally with CGC ratepayers. This agreement expires in April 2006 and is subject to automatic extensions unless specifically terminated by either party. From May 2001 to December 2002, Sequent operated under a bailment agreement and annually paid $0.3 million to manage CGC s assets.

Transportation and storage transactions In our wholesale marketing and risk management business, we also contract for our own 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 then 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. Prices for future delivery periods at many locations are readily available. We capture margin by locking in the economic 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. 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.

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Peaking services Wholesale services generates operating margin through the sale of peaking services primarily to AGLC, which includes receiving a fee from customers that guarantees that those customers will receive gas under the contract under peak conditions. The primary customer for these peaking services has historically been AGLC. Under these peaking services, wholesale services recorded gross revenues of $10.6 million, $11.4 million and zero in 2003, 2002 and fiscal 2001, respectively. All of our peaking arrangements expire March 31, 2004. Wholesale services also incurs costs to support our obligations to serve under these agreements, which will be reduced in whole or in part as the matching obligations expire. If these arrangements, including those with AGLC, are renewed, it is likely that future fees may not be reset at current levels. We will continue to aggressively enter into new peaking transactions as well as work toward extending those that are set to expire.

Competition Sequent, although regionally focused in the eastern half of the United States, competes for natural gas suppliers and customers with national and regional full-service energy providers, energy merchants, several of the large commercial and investment banks and natural gas producers. Due to the events in our industry in the last four years, the amount of competition has been significantly reduced. Our success is based on our ability to aggregate competitively priced commodities and services from our transportation and storage capacity and tailor our services to the customers needs. We believe that we will continue to provide the basic services many customers are seeking, and we should benefit from the reduction in the number of competitors.

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 2003, we have added personnel to focus specifically on these opportunities. Our business territory now extends from Texas to Chicago and all other areas of the United States east of the Mississippi River. In the fourth quarter of 2003, we executed four new nonaffiliated asset management transactions and have increased our producer services volumes. 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 lengthened the average tenor of our portfolio to seven months. At December 31, 2003, Sequent s longest-dated contract in its portfolio was nine years, with contract terms ranging from one day to nine years. Sequent s firm capacity commitments currently are

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$9.4 million in 2004

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$2.6 million in 2005

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$1.8 million in 2006

Seasonality Fixed cost commitments are generally incurred evenly over the year, while our margins generated through the use of these assets are generally greatest in the winter for the heating season and 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 2004. Given the continued exit of marketers due to business repositioning and credit limitations, Sequent should benefit through increased market share. Additionally, although we manage our business with limited open positions and value at risk (VaR), we could have increased earnings volatility in our reported results due to the rescission of EITF 98-10 and our adoption of EITF 02-03, as more fully discussed below under Energy marketing and risk management activities.

Energy marketing and risk management activities During 2003, 2002 and fiscal 2001, we accounted for derivative transactions in connection with our energy marketing activities on a mark-to-market basis in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS 133), and during 2002 and 2001 we accounted for nonderivative energy and energy-related activities in accordance with EITF 98-10.

Under these methods, we recorded energy commodity contracts (including both physical transactions and financial instruments) at fair value, with unrealized gains and/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.

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Effective January 1, 2003, we adopted EITF Issue No. 02-03, which rescinded EITF 98-10 and reached two general conclusions:

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Contracts that do not meet the definition of a derivative under SFAS 133 should not be marked to fair market value.

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Revenues should be shown in the income statement net of costs associated with trading activities, whether or not the trades are physically settled.

Our adoption of EITF 02-03 had the following impact:

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We recorded an adjustment to the carrying value of our nonderivative trading instruments (principally our storage capacity contracts) to zero, and now account for them using the accrual method of accounting.

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We recorded an adjustment to the value of our natural gas inventories used in our wholesale services segment to the lower of average cost or market; they were previously recorded at fair value. This resulted in the cumulative effect of a change in accounting principle in our statement of consolidated income for the three months ended March 31, 2003 of $12.6 million ($7.8 million net of taxes), which resulted in a decrease of $12.6 million to our energy marketing and risk management assets and a decrease in accumulated deferred income taxes of $4.8 million in our accompanying consolidated balance sheet.

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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 2002 and fiscal 2001 are shown net of costs associated with trading activities.

Sequent recorded unrealized gains of $0.7 million, excluding the cumulative effect of a change in accounting principle, during 2003, and unrealized gains of $4.1 million and $2.9 million for 2002 and fiscal 2001 related to changes in the fair value of derivative instruments utilized in our energy marketing and risk management activities.

The tables below illustrate the change in the net fair value of the derivative instruments and energy-trading contracts during 2003 and 2002 and provide details of the net fair value of contracts outstanding as of December 31, 2003. Sequent s storage positions are affected by price sensitivity in the New York Mercantile Exchange, Inc. (NYMEX) average price.

(Unaudited)		
In millions	2003	2002
Net fair value of contracts outstanding at beginning of period	$6.8	$2.9
Cumulative effect of change in accounting principle	(12.6)	-
Net fair value of contracts outstanding at beginning of period, as adjusted	(5.8)	2.9
Contracts realized or otherwise settled during period	1.5	(4.9)
Change in net fair value of contracts (losses) gains	(0.8)	8.8
Net fair value of new contracts entered into during period	-	-
Net fair value of contracts outstanding at end of period	($5.1)	$6.8

The sources of our net fair value at December 31, 2003 are as follows:

(Unaudited)

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)	$5.6	$(1.0)	$-	$-	$4.6
Prices provided by other external sources	(9.8)	0.1	-	-	(9.7)

(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.

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We had a net risk management liability at December 31, 2003 of $5.1 million compared to a net risk management asset of $6.8 million at December 31, 2002. We determined the amounts for 2002 relating to gas storage inventory on a mark-to-market basis, which was the appropriate accounting method at that time. We recorded the gas storage inventory in 2003 on an accrual basis, at the lower of average cost or market. Therefore, these amounts are not directly comparable. The fair value of our gas storage inventory position at December 31, 2003 was higher than average cost, but the fair value is not reflected in the financial statements due to the accounting rules now in effect.

The fair value of this inventory at December 31, 2003 in excess of average cost, using a simple calculation to compare the forward value using market prices at the expected withdrawal period with the cost of inventory included in the balance sheet, was approximately $5.3 million. Additionally, $1.9 million of this value must be shared under our asset management agreements but would be recorded in accounts payable. This net $3.4 million incremental value would have been reflected in our earnings for the year under mark-to-market accounting.

Storage Inventory Outlook The graph below reflects the NYMEX natural gas prices as of December 31, 2003, also known as the NYMEX forward curve, through November 2004. These are the prices on December 31, 2003 at which we could buy natural gas at the Henry Hub for delivery in the time period of January through November 2004.

Open futures contracts represents the volume in contract equivalents of the transactions we executed to economically hedge our storage inventory. As of December 31, 2003, the expected withdrawal schedule of this inventory and its weighted average costs are reflected in the entry, physical withdrawal schedule. Our futures contracts qualify as derivatives under SFAS 133 and are accounted for at fair value (mark-to-market). However, the storage inventory is accounted for under the accrual method, at the lower of average cost or market, resulting in a timing mismatch in earnings recognition.

We recognize the gains or losses on the futures contracts in the period the price changes; we recognize the gains or losses on the storage inventory as the gas is withdrawn from storage. The schedule 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, 2003. This gross margin could change as we adjust our daily injection and withdrawal plans due to changes in market conditions.

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, whereby 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 managed similar to the way traditional reservoir and salt dome storage transactions are evaluated. However, these transactions have elements that qualify as derivatives in accordance with SFAS 133.

Under SFAS 133, the transactions are considered financing arrangements when the contracts contain volumes that are payable or repaid at determinable dates and at a specific point in 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). Park and loan volumes represents the contract equivalent for the volumes of our park and loan transactions as of December 31, 2003, that is not already accounted for at fair value. Gross margin from park and loans represents the gross margin from those transactions expected to be recognized in future periods based on the forward curves at December 31, 2003.

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(Unaudited)

In millions, except number of contracts and WACOG	Jan. 2004 (1)	Feb. 2004	Mar. 2004	Apr. 2004	May 2004	June 2004	July 2004
Open futures contracts (short)	(156)	(218)	(76)	-	-	-	69
Physical withdrawal schedule as of December 31, 2003 (number of contracts)							
Salt dome (WACOG = $5.68)	102	-	-	-	-	-	-
Reservoir (WACOG = $4.93)	54	218	76	-	-	-	(69)
Total	156	218	76	-	-	-	(69)
Expected gross margin, after regulatory sharing (2)							
Salt dome	$0.4	$1.1	$0.4	$-	$-	$-	$-
Reservoir	1.2	0.3	-	-	-	-	-

(1)

January futures expired on December 29, 2003; however, they are included herein as they coincide with the January storage withdrawals.

(2)

As a result of our positions, a $0.10 parallel change in future NYMEX prices would impact our EBIT by $0.3 million at December 31, 2003. A $0.10 change in the price of gas realized on the withdrawal of physical inventory would impact our EBIT by $0.3 million. As shown, our net position is flat, and price movements should only affect timing of earnings between periods as futures contracts are marked to market but inventory is recorded at lower of average cost or market.

(Unaudited)

In millions, except number of contracts	Jan. 2004	Feb. 2004	Mar. 2004	Apr. 2004	May 2004	June 2004	July 2004	Aug. 2004	Nov. 2004
Park and (loan) volumes (number of contracts)	(28)	(10)	(112)	(35)	40	20	50	15	60
Expected gross margin from park and loans	$0.1	$-	$0.4	$-	$-	$-	$-	$-	$-

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Results of Operations The results of operations for wholesale services are as follows:

(Unaudited)

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	$41.2	$23.0	$11.6	$18.2	$11.4
Cost of sales	1.4	0.3	0.2	1.1	0.1
Operating margin	39.8	22.7	11.4	17.1	11.3
Operation and maintenance expenses	19.4	13.2	6.1	6.2	7.1
Depreciation and amortization	0.1	-	-	0.1	-
Taxes other than income	0.4	0.4	-	-	0.4
Total operating expenses	19.9	13.6	6.1	6.3	7.5
Operating income	19.9	9.1	5.3	10.8	3.8
Other loss	(0.3)	-	(2.2)	(0.3)	2.2
EBIT	$19.6	$9.1	$3.1	$10.5	$6.0

Metrics	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Physical sales volumes (Bcf/day)	1.75	1.39	0.1	26%	1,290%

2003 compared to 2002 EBIT increased $10.5 million from 2002, primarily due to a $17.1 million increase in operating margin, offset by an increase of $6.3 in operating expenses.

Operating margin increased $17.1 million due primarily to Sequent s optimization of various transportation and storage assets, mainly in the first quarter when natural gas prices were highly volatile. 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 increase in earnings resulted in $12.6 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. This was partly offset by lower natural gas volatility created by unseasonably cool temperatures in the Southeast, Midwest 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 $6.3 million, primarily due to a $3.1 million increase in corporate costs and a $3.2 million increase primarily due to personnel and outside consulting costs incurred while growing the business.

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.

2002 compared to fiscal 2001 The increase in EBIT of $6.0 million for 2002 as compared to fiscal 2001 was due to increased operating margin of $11.3 million and a $2.2 million decrease in other loss, offset by a $7.5 million increase in operating expenses.

Operating margin increased $11.3 million, primarily from increased weather volatility from warmer-than-normal weather in the Northeast; two hurricanes during the late summer, colder weather in November and December and an overall increase in volumes sold. These weather-related events caused interruption in the supply/demand equilibrium between the affected production and market areas, resulting in wide geographical pricing disparities. Sequent used its access to contracted assets and its expertise in logistics to maximize the profit opportunity by flowing gas on the most economical path available. Additionally, operating margin was positively impacted by peaking services, which were not provided in fiscal 2001. Physical gas sales volumes increased from 0.1 Bcf/day in fiscal 2001 to 1.4 Bcf/day in 2002.

Operating expenses increased $7.5 million, primarily from the addition of personnel to support growth in the business and a full year of operating expenses following Sequent s formation in early 2001. Other loss decreased $2.2 million primarily due to the write-off in fiscal 2001 of our investment in Etowah LNG of $2.6 million, resulting from the termination of the joint venture partnership originally formed in 1998.

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Energy Investments

Our energy investments segment includes our investments in SouthStar and US Propane, the results of operations and financial condition of AGL Networks, LLC (AGL Networks) and Utilipro through the date of its sale in 2001.

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SouthStar is a joint venture formed in 1998 by our subsidiary, Georgia Natural Gas Company, Piedmont Natural Gas Company (Piedmont) and Dynegy Inc. (Dynegy) to market natural gas and related services to retail customers, principally in Georgia. Initially, we owned a 50% interest in SouthStar, Piedmont owned a 30% interest and Dynegy owned the remaining 20% interest.

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. Upon closing, we owned a noncontrolling 70% financial interest in SouthStar and Piedmont owned the remaining 30%. Our 70% interest is noncontrolling because all significant matters require approval by both owners. We recognize our equity in earnings of SouthStar based upon our ownership interest plus the amount recognized for disproportionate sharing, as discussed below. For all periods prior to February 18, 2003, SouthStar s earnings have been allocated to our subsidiary based upon our ownership interests in those periods or 50%.

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 a monthly year-to-date average of approximately 557,700 customers. This represents a market share of approximately 37.5% as of December 31, 2003, which is relatively consistent with its market share of 38.2% in the prior year.

Disproportionate sharing SouthStar s operating policy contains provisions for the disproportionate sharing of earnings with our partner in SouthStar, Piedmont, when SouthStar s annual earnings before taxes exceed a certain threshold. The annual threshold is calculated each year based on a cumulative and annual return on contributed capital. SouthStar s operating policy requires that earnings above the threshold be allocated at various percentages based on actual margin generated in the four defined service areas of the operating policy, and distributed annually to each owner as a mandatory distribution. Disproportionate sharing is only applicable to our original 50% financial interest in SouthStar. No disproportionate sharing of earnings had occurred prior to December 2003 because the owners had not reached an agreement on how disproportionate sharing should be calculated.

On December 31, 2003, the owners resolved their differences over the interpretation of the provisions in the operating policy that provided for the disproportionate sharing of earnings through an agreement that provides for SouthStar s 2003 earnings to be allocated 80% to us and 20% to Piedmont, less income allocable to Dynegy prior to February 18, 2003. The agreement resulted in our recognition of $5.9 million of equity earnings for disproportionate sharing for the 12 months ended December 31, 2003.

The agreement also provided for a one time cash distribution of $40 million to the owners on December 31, 2003, which was allocated $34 million to us and $6 million to Piedmont. The agreement further resolved all issues related to the allocation of earnings for all years prior to 2003 by allocating earnings for such prior years based on the current owners respective interests for such prior fiscal years.

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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 telecommunication 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.

In 2003, AGL Networks determined that it would focus on wholesale telecommunications customers. In particular, these customers would use our network to provide communications services to commercial entities or to create private metropolitan networks. Our primary goals for this business in the next 12 to 15 months are to

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increase revenues through our sales efforts to achieve break-even or better results by the end of 2004

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maintain control of capital costs for connecting carriers to the network

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maintain control of sales and operating expenses

Competition AGL Network s 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 is a unique continuous ring and, as such, will be subscribed ahead of most competitors as market conditions support greater use of our product.

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US Propane is a joint venture formed in 2000 by us, Atmos Energy Corporation, Piedmont and TECO Energy, Inc. During 2003, 2002 and fiscal 2001, we owned 22.36% of the limited partnership interest in US Propane. US Propane owns all the general partnership interests, directly or indirectly, and approximately 25% of the limited partnership interests in Heritage, a publicly traded marketer of propane.

On January 20, 2004, we closed on an agreement to sell our general and limited partnership interests in Heritage. The agreement involved our subsidiaries, AGL Propane Services Inc. and AGL Energy Corporation, and the three other nonaffiliated utility partners. The aggregate transaction was valued at $130 million. Upon closing, we received $29 million for the sale of our interests. We do not expect to recognize a material gain or loss on the transaction in 2004.

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Results of operations The results of operations for energy investments are as follows:

(Unaudited)

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	$6.5	$2.0	$9.2	$4.5	($7.2)
Cost of sales	0.7	0.5	1.2	0.2	(0.7)
Operating margin	5.8	1.5	8.0	4.3	(6.5)
Operation and maintenance expenses	9.3	7.5	11.5	1.8	(4.0)
Depreciation and amortization	0.9	0.3	0.9	0.6	(0.6)
Taxes other than income	0.5	0.2	0.5	0.3	(0.3)
Total operating expenses	10.7	8.0	12.9	2.7	(4.9)

Operating loss	(4.9)	(6.5)	(4.9)	1.6	(1.6)
Equity earnings from SouthStar	45.9	27.0	13.7	18.9	13.3
Gain on the sale of Utilipro	-	-	10.9	-	(10.9)
Other income	2.1	3.1	1.6	(1.0)	1.5
Total other income	48.0	30.1	26.2	17.9	3.9
EBIT	$43.1	$23.6	$21.3	$19.5	$2.3

Metrics	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
SouthStar					
Average customers (in thousands)	557.7	563.6	555.5	(1.1%)	1.5%
Market share in Georgia	37.5%	38.2%	37.2%	(1.8)	2.7
AGL Networks					
% dark fiber miles leased Atlanta	9.4%	1.6%	-	487.5	100.0
% dark fiber miles leased - Phoenix	5.8%	4.0%	-	45.0	100.0

(1)

Includes 100% of the results of SouthStar.

2003 compared to 2002 The increase in EBIT of $19.5 million for 2003 compared to 2002 was primarily the result of increased earnings from SouthStar of $18.9 million and $1.5 million from US Propane, partially offset by decreased EBIT from AGL Networks of $0.6 million.

The $4.3 million increase in operating margin was due to a $3.0 million increase in AGL Networks monthly recurring contract revenues, resulting from an increase in the number of executed leases and a $2.3 million sales-type lease completed in the first quarter of 2003. Also contributing to the year over year change is the recognition in 2002 of a $1.0 million feasibility fee. No such fees were recognized in 2003. The $2.7 million increase in operating expenses was primarily due to business growth at AGL Networks and higher corporate overhead costs.

The $17.9 million increase in other income was primarily the result of increased earnings from SouthStar of $18.9 million. The increased contribution from SouthStar was due primarily to disproportionate sharing of $5.9 million, higher volumes and related operating margin, additional 20% ownership interest, which contributed approximately $9.0 million, and lower bad debt and operating expenses. US Propane s earnings increased $1.5 million, primarily due to colder weather as compared to last year. The increases in other income were partially offset by a $2.0 million contract renewal payment in 2002 associated with the sale of Utilipro.

#

2002 compared to fiscal 2001 Effective March 2, 2001, we sold substantially all the assets of Utilipro for $17.9 million, resulting in a pretax and aftertax gain of $10.9 million and $7.1 million, respectively, in fiscal 2001. Excluding this gain, the increase in EBIT in 2002 compared to fiscal 2001 was $13.2 million.

The increase in EBIT of $13.2 million for 2002 compared to fiscal 2001 was primarily the result of increased earnings from SouthStar of $13.3 million. These increases in EBIT were offset by a $1.6 million decrease in EBIT at AGL Networks.

The $6.5 million decrease in operating margin was due to a decrease of $7.9 million in Utilipro s operating margin from its sale in March 2001. The decrease was offset by a $1.5 million increase in AGL Networks operating margin due to growth of the business.

The $4.9 million decrease in operating expenses was due to the absence of $8.5 million of Utilipro operating expenses following its sale in March 2001. The decrease was offset by a $3.8 million increase in AGL Networks operating expenses due to additional personnel to support the growth of the business.

The $3.9 million increase in other income was primarily the result of increased earnings from SouthStar of $13.3 million due to lower bad debt expense as a result of an increase in credit quality of retail customers and lower wholesale costs and a $2.0 million contract renewal payment in 2002 associated with the sale of Utilipro. The increases were offset by a $10.9 million pretax gain recorded in 2001 for the sale of Utilipro.

#

Corporate

Our corporate segment includes the results of operations and financial condition of 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 a commercial paper program, the issuance of various debt and hybrid securities, and other financing arrangements.

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 The results of operations for our corporate segment are as follows:

(Unaudited)

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Operating revenues	$0.1	($0.2)	$5.8	$0.3	($6.0)
Cost of sales	-	-	4.0	-	(4.0)
Operating margin	0.1	(0.2)	1.8	0.3	(2.0)
Total operating expenses	4.6	8.4	(5.9)	(3.8)	14.3
Loss on sale of Caroline Street campus	(5.6)	-	-	(5.6)	-
Operating (loss) income	(10.1)	(8.6)	7.7	(1.5)	(16.3)
Other loss	(1.3)	(1.5)	(9.1)	0.2	7.6
EBIT	($11.4)	($10.1)	($1.4)	($1.3)	($8.7)

2003 compared to 2002 The decrease in EBIT of $1.3 million for 2003 compared to 2002 was primarily the result of a loss of $5.6 million on the sale of the buildings and their contents at our Caroline Street campus. The decrease was offset by decreased operating expenses of $3.8 million for 2003 as compared to 2002.

The $3.8 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. We recorded $6.4 million for the termination of the automated meter reading contract, $1.6 million for the write-off of capital costs related to a terminated risk management software implementation project and $1.5 million in employee severance costs in 2002. These decreases were offset by 2003 expenses not allocated to our operating segments, consisting primarily of $5.3 million in increased compensation and benefit costs.

2002 compared to fiscal 2001 The decrease in EBIT of $8.7 million for 2002 compared to fiscal 2001 was due to operating expenses recorded in 2002 that were not allocated to our operating segments. We recorded $6.4 million charge for the termination of the automated meter reading contract, $1.6 million for the write-off of capital costs related to a risk management software implementation project and $1.5 million in employee severance costs.

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Discussion was derived from the unaudited financial statements

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 agreements (Credit Facility) and borrowings or stock issuances in the long-term capital markets to meet our capital and liquidity requirements. For the foreseeable future, we believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures. However, 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

o

the seasonal nature of the natural gas business and our resulting short-term borrowing requirements, which typically peak during colder months

o

increased gas supplies required to meet our customers   needs during cold weather

o

regulatory changes and changes in ratemaking policies of regulatory commissions

o

contractual cash obligations and other commercial commitments

o

interest rate changes

o

pension and postretirement benefit costs

o

changes in income tax laws

o

changes in wholesale prices and customer demand for our products and services

o

margin requirements resulting from significant increases or decreases in our commodity prices

o

operational risks

The availability of borrowings under our Credit Facility is subject to conditions specified within the Credit Facility, which we currently meet. These conditions include compliance with certain financial covenants and the continued accuracy of representations and warranties contained in the agreements. Although we had no borrowings outstanding under our Credit Facility at December 31, 2003, 2002 and 2001, our unused availability under our Credit Facility was limited by our total debt-to-capital ratio at December 31, 2002 and 2001, as represented in the table below.

(Unaudited)

In millions	**Dec. 31, 2003**	**Dec. 31, 2002**	**Dec. 31, 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Unused availability under the Credit Facility	$500.0	$244.1	$110.7	$255.9	$133.4
Cash and cash equivalents	16.5	8.4	7.3	8.1	1.1
Total cash and available liquidity under the Credit Facility	$516.5	$252.5	$118.0	$264.0	$134.5

In January 2003, the FASB released FASB Interpretation No. 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (FIN 45). For many of the guarantees or indemnification agreements we issue, FIN 45 requires disclosure of the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The table below illustrates our expected commercial commitments that are outstanding as of December 31, 2003 and meet the disclosure criteria required by FIN 45:

(Unaudited)

			Commitments Due before December 31,		
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Guarantees (1) (2)	$228.5	$228.5	-	-	-
Standby letters of credit, performance/ surety bonds	7.9	7.9	-	-	-
Total other commercial commitments	$236.4	$236.4	$-	$-	$-

(1)

$176.2 million of these guarantees support credit exposures in Sequent s energy marketing and risk management business. In the event that Sequent defaults on any commitments under these guarantees, these amounts would become payable by us as guarantor.

(2)

We provide guarantees on behalf of our affiliate, SouthStar. We guarantee 70% of SouthStar s obligations to Southern Natural Gas Company and its affiliate South Georgia Natural Gas Company (together referred to as SONAT) under certain agreements between the parties up to a maximum of $7.0 million if SouthStar fails to make payment to SONAT. Under a second such guarantee, we guarantee 70% of SouthStar s obligations to AGLC under certain agreements between the parties up to a maximum of $42.3 million, which represents our share of SouthStar s maximum credit support obligation to AGLC under its tariff.

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Contractual Obligations

Presented below is a summary of our contractual obligations as of December 31, 2003.

(Unaudited)

			Payments Due before December 31,		
In millions	Total	2004	2005 & 2006	2007 & 2008	2009 & Thereafter
Long-term debt (1)	$1,033.1	$77.0	$-	$-	$956.1
Pipeline charges, storage capacity and gas supply (2)	709.0	219.8	234.3	97.2	157.7
PRP costs (3)	404.3	81.6	162.0	160.7	-
Short-term debt	306.4	306.4	-	-	-
Environmental response costs (3)	83.0	40.3	22.8	3.8	16.1
Operating leases (4)	82.6	11.8	21.6	16.4	32.8
Communication/network service and maintenance	17.8	8.2	9.6	-	-
Pension contribution (5)	15.0	15.0	-	-	-
Total	$2,651.2	$760.1	$450.3	$278.1	$1,162.7

(1)

Includes $225.3 million of Trust Preferred Securities, callable in 2006 and 2007.

(2)

Charges recoverable through a PGA mechanism or alternatively billed to Marketers.

(3)

Charges recoverable through rate rider mechanisms.

(4)

We have certain operating leases with provisions for step rent or escalation payments, or certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS No. 13, Accounting for Leases. However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

(5)

We calculate the amount of funding using an actuarial method called the projected unit cost method. However, it is not necessarily required and we may fund lessor amounts in the future. We have not included expected contributions for years subsequent to 2004.

Cash flow from operating activities

Year-to-year changes in our operating cash flows are primarily the result of changes in our operating results, variability in the distribution of earnings we receive from our equity investments and the timing associated with working capital items such as cash collections from our customers; payments for operating expenses to our vendors, employees, income taxes and interest. 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.

Our statement of cash flows is prepared using the indirect method. Under this method, net income is reconciled to cash flows from operating activities by adjusting net income for those items that impact net income but do not result in actual cash receipts or payments during the period. These reconciling items include depreciation, undistributed earnings from equity investments, changes in deferred income taxes, gains or losses on the sale of assets and changes in the balance sheet for working capital from the beginning to the end of the period.

(Unaudited)

In millions	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Cash provided by operating activities	$122.1	$285.5	$99.8	($163.4)	$185.7
Cash flow used in investing activities	(145.1)	(160.4)	(651.1)	15.3	490.7
Cash flow provided by (used in) financing activities	31.1	(124.0)	552.1	155.1	(676.1)

#

2003 compared to 2002 Our cash flow from operations in 2003 was $122.1 million, a decrease of $163.4 million from 2002. This decrease was primarily the result of increased spending for injection of natural gas inventories of approximately 11 Bcf. The weighted average cost of this inventory increased approximately 30% as compared to last year. In addition, we made $21.5 million in pension contributions this year as a result of our continued efforts to fully fund our pension liability. This was offset by increased net income of $24.3 million and cash received from SouthStar of $40.0 million.

2002 compared to fiscal 2001 Our cash flow from operations was $285.5 million for 2002, an increase of $185.7

million from fiscal 2001. This increase was positively impacted by the increase in our energy marketing payables net of the increase in our energy marketing receivables, primarily as a result of growth in transaction volumes in our wholesale services segment. Additionally, we received cash of $42.2 million from the sale of natural gas inventories, primarily storage gas sold to the Marketers, in excess of cash purchases. Also, the increase is a result of increased net income of $14.1 million.

Cash flow from investing activities

In 2003, 2002 and fiscal 2001, cash used in investing activities consisted primarily of property, plant and equipment expenditures and in 2003, $20.0 million for the purchase of Dynegy s 20% interest in SouthStar. This was offset by $27.3 million in cash provided from SouthStar and US Propane in 2002. In fiscal 2001, we completed the acquisition of VNG, net of cash acquired, for $541.2 million; this was slightly offset by cash received of $17.9 million from the sale of Utilipro. The following table provides additional information on our property, plant and equipment expenditures and our total capital requirements:

(Unaudited)

	Estimated		**Actual**			
In millions	**Calendar 2004**	**Calendar 2003**	**Calendar 2002**	**Fiscal 2001**	**2003 vs. 2002**	**2002 vs. 2001**
Construction of distribution facilities	$88.6	$53.8	$61.8	$63.2	($8.0)	($1.4)
PRP (1)	87.5	51.3	47.6	50.0	3.7	(2.4)
Telecommunications	2.5	8.2	28.6	2.8	(20.4)	25.8
Other	46.4	45.1	49.0	39.7	(3.9)	9.3
Total property, plant and equipment expenditures	225.0	158.4	187.0	155.7	(28.6)	31.3
ERC (2)	40.3	32.4	36.9	31.6	(4.5)	5.3
Total capital requirements	$265.3	$190.8	$223.9	$187.3	($33.1)	$36.6

(1)

These expenditures include removal costs. We estimate our total future capital expenditures related to the PRP to be $404.3 million. Capital expenditures under this program are expected to end June 30, 2008, unless the program is extended by the GPSC.

(2)

These costs are not included in our cash flows from investing activities as they not considered property, plant and equipment expenditures. They are considered a factor in our capital requirements as we estimate our cash requirements for future years.

2003 compared to 2002 The decrease of $28.6 million or 15.3% in property, plant and equipment expenditures for 2003 as compared to 2002 was primarily due to lower telecommunications expenditures of $20.4 million, as a result of the completion of the metro Atlanta fiber network in 2002, and a decrease in construction of distribution facilities of $8.0 million associated with our distribution operations segment. The $4.5 million decrease in the ERC expenditures was due primarily to work delays in Augusta and Savannah. The estimated ERC capital requirements for 2004 will increase as a result of these delays.

2002 compared to fiscal 2001 The increase of $31.3 million in property, plant and equipment expenditures for 2002 compared to fiscal 2001 was primarily from AGL Networks completion of the metro Atlanta fiber network and the purchase of the Phoenix fiber network.

Estimated 2004 compared to 2003 In 2004, we estimate that our total capital requirements will increase as a result of capital expenditures for construction of distribution facilities and the PRP . Our expected increase in the construction of distribution facilities is primarily from Pivotal s projects next year.

#

As shown in the following unaudited chart, our PRP costs are expected to increase in the next five 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. We expect the annual PRP costs through 2008 will be in the range of $75 - $80 million each year. The PRP recoveries shown in the chart are recorded as revenues and are based upon a formula that allows us to recover operation and maintenance costs that are in excess of those included in AGLC 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.

#

Cash flow from financing activities

Our financing activities are primarily composed of borrowings and payments of short-term debt, payments of Medium-Term notes, borrowings of Senior Notes, cash dividends on our common stock and the issuance of common stock. Our Credit Facility financial covenants and the PUHCA require us to maintain a ratio of total debt to total capitalization of no greater than 70.0%. As of December 31, 2003, we were in compliance with this leverage ratio requirement. The components of our capital structure, as of the dates indicated, are summarized in the following table.

(Unaudited)				
Dollars in millions	Dec. 31, 2003		Dec. 31, 2002	
Short-term debt	$306.4	13.4%	$388.6	18.3%
Current portion of long-term debt	77.0	3.3	30.0	1.4
Senior and Medium-Term notes (1)	730.8	32.0	767.0	36.1
Trust Preferred Securities (2)	225.3	9.9	227.2	10.7
Total debt	1,339.5	58.6	1,412.8	66.5

Common equity	945.3	41.4	710.1	33.5
Total capitalization	$2,284.8	100.0%	$2,122.9	100.0%

(1)

Net of interest rate swaps of ($6.9) million in 2003.

(2)

Net of interest rate swaps of $3.2 million and $6.1 million.

Short-term Debt Our short-term debt is composed of borrowings under our commercial paper program and Sequent s line of credit. The commercial paper program is supported by our Credit Facility, which consists of a $200 million 364-day Credit Facility with a one-year term-out option that expires June 16, 2004; and a $300 million three-year Credit Facility that terminates on August 7, 2005. As of December 31, 2003, we had no outstanding borrowings under the Credit Facility.

In December 2003, Sequent s $15.0 million unsecured line of credit was increased to $25.0 million. Sequent used this 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 2, 2004, and bears interest at the federal funds effective rate plus 0.5%. As of December 31, 2003, the line of credit had an outstanding balance of $2.9 million.

Long-term Debt On July 2, 2003, we issued $225.0 million in Senior Notes Due April 2013. The Senior Notes have an interest rate of 4.45% payable on April 15 and October 15 of each year, beginning October 15, 2003.We used the net proceeds to repay $203.8 million of our Medium-Term notes, discussed below, and approximately $19.6 million of short-term debt. In 2003, we made $207.3 million in Medium-Term note payments, as follows:

o

In April 2003, we exercised our option to call at par two Medium-Term notes totaling $7.2 million before their scheduled maturity dates at a call premium. These notes were scheduled to mature in 2013 and 2014 with interest rates ranging from 7.4% to 7.5%.

o

In July 2003, we exercised our option to redeem $65.3 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2013 and 2023 with interest rates ranging from 7.5% to 8.25%.

o

In October 2003, we repaid on its original due date a $30.0 million Medium-Term note with an interest rate of 5.90%; and we exercised an option to redeem before their scheduled maturity dates of October 2006 and October 2020, respectively, a $10.0 million Medium-Term note, at par, and a $2.0 million Medium-Term note, at a premium bearing interest at a rate of 6.0%, and 6.85%, respectively.

o

In December 2003, we exercised our option to redeem $92.8 million of Medium-Term notes at a call premium. These notes were scheduled to mature in 2005 and 2013 bearing interest rates from 6.55% to 7.2%.

In 2002, we made $93.0 million in scheduled Medium-Term note payments using a combination of cash from operations and proceeds from the commercial paper program. On February 23, 2001, we issued $300.0 million in Senior Notes Due February 2011. These Senior Notes have an interest rate of 7.125% payable on January 14 and July 14. In May 2001, we issued and sold $150.0 million in principal amount of 8.0% Trust Preferred Securities. These Trust Preferred Securities are subject to mandatory redemption in May 2041 and may be redeemed early, beginning in 2006. We used the proceeds of the Senior Notes and Trust Preferred Securities to reduce our commercial paper balance and for general corporate purposes.

#

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 through our wholly owned subsidiary, AGL Capital, for the purpose of hedging the interest rate risk associated with our fixed-rate and variable-rate debt obligations.

Common stock On February 14, 2003, we completed our public offering of 6.4 million shares of common stock. We priced the offering at $22.00 per share and generated net proceeds of approximately $136.7 million, which we used to repay outstanding short-term debt and for general corporate purposes.

On April 16, 2003, we announced a 3.7% increase in our common stock dividend, raising the quarterly dividend from $0.27 per share to $0.28 per share, which equates to an indicated annual dividend of $1.12 per share. This increase in our common stock dividend along with the shares issued in connection with our equity offering resulted in an approximately $10 million increase in dividends paid on our common shares.

Shelf Registration We currently have an active shelf registration statement for up to $750 million of various capital securities, with remaining capacity of approximately $383 million. On September 23, 2003, we filed a second shelf registration with the SEC for authority to increase our capacity to $1.0 billion of various capital securities. We may seek additional financing through debt or equity offerings in the private or public markets at any time.

Credit Rating

Our credit ratings impact our ability to obtain short-term and long-term financing and the cost of such financing. In determining our credit ratings, the rating agencies consider a number of factors. Quantitative factors that appear to be given significant weight include, among other things:

o

earnings

o

operating cash flow

o

total debt outstanding

o

total equity outstanding

o

pension liabilities and funding status

o

the level of capital expenditures and other commitments

o

fixed charges such as interest expense, rent or lease payments

o

payments to preferred stockholders

o

liquidity needs and availability

o

total debt-to-total capitalization ratios

o

various ratios calculated from these factors

Qualitative factors appear to include, among other things, the stability of regulation in each jurisdiction, risks and controls inherent with wholesale services, predictability of cash flows, business strategy, management, corporate governance principles, board experience and independence, industry position and contingencies.

Our credit ratings may be subject to revision or withdrawal at any time by the assigning rating organization and you should evaluate each rating independently of any other rating. We cannot assure you 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. During 2003, no fundamental adverse shift occurred in our ratings profile. The following table presents as of January 23, 2004 the credit ratings on our unsecured debt issues from the three major rating agencies. The ratings are all investment-grade status and the outlooks for all credit ratings are stable.

Type of facility	Moody's	S&P	Fitch
Commercial paper	P-2	A-2	F-2
Medium-Term notes	A3	A-	A
Senior Notes	Baa1	BBB+	A-
Trust Preferred Securities	Baa2	BBB	BBB+

#

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

o

a maximum leverage ratio

o

minimum net worth

o

insolvency events and nonpayment of scheduled principal or interest payments

o

acceleration of other financial obligations

o

change of control provisions

We do not have any trigger events in our debt instruments that are tied to changes in our specified credit ratings or our stock price and have not entered into any transaction that requires us to issue equity based on credit ratings or other trigger events. We are currently in compliance with all existing debt provisions and covenants.

Sequent has certain trade and/or credit contracts that have explicit credit rating trigger events in case of a credit rating downgrade. These rating triggers typically would give counterparties the right to suspend or terminate credit if our credit ratings were 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.

At December 31, 2003, if our credit ratings were downgraded to non-investment grade, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $2.9 million. We believe the existing cash and available liquidity under our Credit Facility is adequate to fund these potential liquidity requirements.

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Discussion was derived from the unaudited financial statements

Qualitative and Quantitative Disclosures about Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business, but is particularly concentrated in our distribution operations segment at AGLC and in our wholesale services segment.

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 financial and other derivative instruments that we use require payments to or receipt of payments from counterparties based on the differential between a fixed and variable price for the commodity, options or other contractual arrangements. We do not designate our derivative instruments that manage our risk exposure to energy prices as hedges under SFAS 133. Our determination of fair value considers various factors, including closing exchange or over-the-counter market price quotations, time value, and volatility factors underlying options and contractual commitments. The maximum terms of these maturities are less than 9 years and represent purchases (long) of 410.4 Bcf and sales (short) of 446.8 Bcf, with approximately 95% of these scheduled to mature in less than 2 years and the remaining 5% in 3   9 years.

The following table includes the fair values and average values of our energy marketing and risk management assets and liabilities as of December 31, 2003 and 2002. We base the average values on monthly averages for the 12 months ended December 31, 2003 and 2002.

(Unaudited)

	Asset			
	Average 12-months values		Value at:	
In millions	Calendar 2003	Calendar 2002	Dec. 31, 2003	Dec. 31, 2002
Natural gas contracts	$13.6	$18.6	$13.2	$24.7

(Unaudited)

	Liability			
	Average 12-months values		Value at:	
In millions	Calendar 2003	Calendar 2002	Dec. 31, 2003	Dec. 31, 2002
Natural gas contracts	$14.3	$12.6	$18.3	$17.9

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. On September 30, 2003, our RMC approved a proposal to change Sequent s 20-day VaR holding period to 10 days. This change was made to better align our risk reporting with that of our peers in the energy industry.

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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. 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, 2003 had the following 1-day and 10-day holding period VaRs:

(Unaudited)		
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.

Under our risk management policy, we attempt to mitigate substantially all of our commodity price risk associated with Sequent s storage gas portfolio to 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, 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 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 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 for 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 statements 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 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.

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.

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Sequent manages underground storage for our utilities and holds certain capacity rights on its own behalf. The underground storage is of two types:

o

reservoir storage, where supplies are generally injected and withdrawn on a seasonal basis

o

salt dome high-deliverability storage, where supplies may be periodically injected and withdrawn on relatively short notice

Energy Investments. SouthStar utilizes financial contracts to hedge the price volatility of natural gas. SouthStar considers these financial contracts (futures, options and swaps) to be derivatives, with prices based on selected market indices. SouthStar reflects the derivatives transactions that qualify as cash-flow hedges in its balance sheets at the fair values of the open positions with the corresponding unrealized gain or loss included in other comprehensive income. SouthStar reflects the derivatives transactions that are not designated as hedges in its balance sheets with the corresponding unrealized gains or losses included in cost of sales in SouthStar s statement of income.

SouthStar also 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 (EITF 99-02).

Over Ninety percent of SouthStar s residential customers buy gas on a variable pricing basis and 6% buy gas on a fixed-price basis. SouthStar hedges the price risk associated with these fixed-price sales using physical contracts and derivative instruments.

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 $100.0 million of the Senior Notes Due 2011, $100.0 million of the Senior Notes Due 2013 and $75.0 million of the $150.0 million Trust Preferred Securities Due in 2041.

(Unaudited)

Market Value of Interest Rate Swap Derivatives

Dollars in millions				Market Value as of:	
Notional Amount	Fixed-Rate Payment	Variable Rate Received	Maturity	Dec.31, 2003	Dec. 31, 2002
$75.0	8.0%	3-month LIBOR (1) Plus 131.5 bps (2)	May 15, 2041	$3.2	$6.1
$100.0	7.1%	6-month LIBOR Plus 340.0 bps	January 14, 2011	(1.8)	$-
$100.0	4.5%	6-month LIBOR Plus 61.5 bps	April 15, 2013	(5.1)	$-

(1)

London Interbank Offered Rate.

(2)

Basis points.

At December 31, 2003, our variable-rate debt consisted of $303.5 million in commercial paper, $2.9 million of Sequent s line of credit and $275.0 million of the swapped portions of the $300.0 million Senior Notes Due 2011, $225 million Senior Notes Due 2013 and $150.0 million Trust Preferred Securities. Based on outstanding borrowings at quarter end, a 100-basis-point change in market interest rates from 1.3% to 2.3% at December 31, 2003 would result in a change in annual pretax expense of $5.8 million. As of December 31, 2003, $77.0 million of long-term fixed-rate obligations are scheduled to mature in the following 12 months. Any new debt obtained to refinance this obligation would be exposed to changes in interest rates.

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Credit Risk

Distribution Operations. AGLC has a concentration of credit risk where we charge out and collect from Marketers and poolers, costs for this segment. AGLC 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 AGLC's tariff allow AGLC to obtain security support in an amount equal to a minimum of two times a Marketer's highest month's estimated bill from AGLC. For 2003, the four largest Marketers based on customer count, one of which was SouthStar, accounted for approximately 57.8% of our operating margin and 62.2% of distribution operations' operating margin.

In addition, AGLC bills intrastate delivery service to Marketers in advance rather than in arrears. We require security support in the form of cash deposits, letters of credit or surety bonds from acceptable issuers or corporate guarantees from investment-grade entities. The RMC reviews the adequacy of security support coverage, credit rating profiles of security 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 AGLC's credit risk exposure to Marketers.

AGLC also faces potential credit risk in connection with assignments to Marketers of interstate pipeline transportation and storage capacity. Although AGLC assigned 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 AGLC. 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 that 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, 2003, Sequent s top 20 counterparties represent approximately 72% of the total counterparty exposure of $190.2 million, derived by adding the top 20 counterparties exposures divided by the total of Sequent s counterparties exposures.

As of December 31, 2003, Sequent s counterparties, or the counterparties guarantors, had a weighted average S&P equivalent credit rating of BBB compared to BBB+ at December 31, 2002. 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.

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To arrive at the weighted average credit rating, the assigned internal rating for each counterparty 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 table shows Sequent's commodity receivable and payable positions as of December 31, 2003 and 2002:

(Unaudited)

Gross receivables	As of:		
In millions	Dec. 31, 2003	Dec. 31, 2002	Change
Receivables with netting agreements in place:			
Counterparty is investment grade	$288.3	$188.2	$100.1
Counterparty is non-investment grade	13.1	22.8	(9.7)
Counterparty has no external rating	8.8	25.1	(16.3)
Receivables without netting agreements in place:			
Counterparty is investment grade	14.7	3.7	11.0
Counterparty is non-investment grade	-	0.4	(0.4)
Counterparty has no external rating	-	-	-
Amount recorded on balance sheet	$324.9	$240.2	$84.7

(Unaudited)

Gross payables	As of:		
In millions	Dec. 31, 2003	Dec. 31, 2002	Change
Payables with netting agreements in place:			
Counterparty is investment grade	$205.4	$139.8	$65.6
Counterparty is non-investment grade	31.4	36.6	(5.2)
Counterparty has no external rating	45.0	28.4	16.6
Payables without netting agreements in place:			
Counterparty is investment grade	29.3	37.4	(8.1)
Counterparty is non-investment grade	2.5	2.2	0.3
Counterparty has no external rating	15.4	6.3	9.1
Amount recorded on balance sheet	$329.0	$250.7	$78.3

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

o

SouthStar scores firm residential and small commercial customers using a national reporting agency and enroll, without security, only those customers that meet or exceed SouthStar s credit threshold.

o

SouthStar investigates potential interruptible and large commercial customers through reference checks, review of publicly available financial statements and review of commercially available credit reports.

o

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.

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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, 2004	/s/ Richard T. O Brien
	Executive Vice President and Chief Financial Officer

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