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

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended September 30, 2006

OR

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

For the transition period from to

Commission File Number 1-14174

AGL RESOURCES INC.

(Exact name of registrant as specified in its charter)

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

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	**Outstanding as of October 20, 2006**
Common Stock, $5.00 Par Value	77,696,090

AGL RESOURCES INC.

Quarterly Report on Form 10-Q

For the Quarter Ended September 30, 2006

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PART I – Financial Information
Item 1. Financial Statements

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

In millions, except share data	September 30, 2006	December 31, 2005	September 30, 2005
Current assets			
Cash and cash equivalents	$14	$32	$58
Receivables (less allowance for uncollectible accounts of $16 at Sep. 30, 2006, $15 at Dec. 31, 2005 and $13 at Sep. 30, 2005)	500	1,220	839
Inventories	627	543	518
Unrecovered environmental remediation costs – current	28	31	29
Unrecovered pipeline replacement program costs – current	26	27	24
Energy marketing and risk management assets	174	103	161
Other	143	78	190
Total current assets	1,512	2,034	1,819
Property, plant and equipment			
Property, plant and equipment	4,943	4,791	4,727
Less accumulated depreciation	1,538	1,458	1,424
Property, plant and equipment-net	3,405	3,333	3,303
Deferred debits and other assets			
Goodwill	425	420	405
Unrecovered pipeline replacement program costs	258	276	331
Unrecovered environmental remediation costs	151	165	180
Other	89	85	112
Total deferred debits and other assets	923	946	1,028
Total assets	$5,840	$6,313	$6,150
Current liabilities			
Payables	$540	$1,041	$820
Short-term debt	441	522	344
Accrued expenses	88	105	118
Energy marketing and risk management liabilities	59	117	318
Accrued pipeline replacement program costs – current	35	30	47
Accrued environmental remediation costs – current	14	13	8
Other	139	133	152
Total current liabilities	1,316	1,961	1,807
Accumulated deferred income taxes	535	423	412
Long-term liabilities			
Accrued pipeline replacement program costs	212	235	270
Accumulated removal costs	160	156	155
Accrued pension obligations	93	88	87
Accrued environmental remediation costs	88	84	90
Accrued postretirement benefit costs	45	52	54
Other	139	162	177
Total long-term liabilities	737	777	833
Commitments and contingencies (Note 8)			
Minority interest	37	38	31
Capitalization			
Long-term debt	1,634	1,615	1,616
Common shareholders' equity, $5 par value; 750,000,000 shares authorized	1,581	1,499	1,451
Total capitalization	3,215	3,114	3,067
Total liabilities and capitalization	$5,840	$6,313	$6,150

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

In millions, except per share amounts	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Operating revenues	$434	$393	$1,914	$1,736
Operating expenses				
Cost of gas	190	191	1,064	972
Operation and maintenance	111	106	341	334
Depreciation and amortization	33	33	101	99
Taxes other than income	10	9	30	30
Total operating expenses	344	339	1,536	1,435
Operating income	90	54	378	301
Other (expense) income	-	-	(2)	2
Interest expense	(32)	(27)	(91)	(79)
Minority interest	-	(2)	(19)	(18)
Earnings before income taxes	58	25	266	206
Income taxes	22	10	101	79
Net income	$36	$15	$165	$127
Basic earnings per common share	$0.46	$0.19	$2.13	$1.64
Diluted earnings per common share	$0.46	$0.19	$2.12	$1.62
Cash dividends paid per common share	$0.37	$0.31	$1.11	$0.93
Weighted-average number of common shares outstanding				
Basic	77.5	77.5	77.6	77.2
Diluted	77.9	78.1	78.1	77.8

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(UNAUDITED)

In millions, except per share amount	Common Stock Shares	Common Stock Amount	Premium on common shares	Retained Earnings	Accumulated other comprehensive income	Shares Held in Treasury	Total
Balance as of December 31, 2005	77.8	$389	$655	$508	$(53)	$-	$1,499
Comprehensive income:							
Net income	-	-	-	165	-	-	165
Unrealized gain from hedging activities (net of taxes of $5)	-	-	-	-	10	-	10
Total comprehensive income							175
Dividends on common shares ($1.11 per share)	-	-	1	(87)	-	2	(84)
Benefit, dividend reinvestment and share purchase plans	0.3	1	2	-	-	-	3
Issuance of treasury shares	0.4	-	(3)	(2)	-	13	8
Purchase of treasury shares	(0.7)	-	-	-	-	(26)	(26)
Stock-based compensation expense (net of tax benefit of $2)	-	-	6	-	-	-	6
Balance as of September 30, 2006	77.8	$390	$661	$584	$(43)	$(11)	$1,581

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(UNAUDITED)

In millions	Nine months ended September 30, 2006	2005
Cash flows provided by (used in) operating activities		
Net income	$165	$127
Adjustments to reconcile net income to net cash flow provided by operating activities		
Depreciation and amortization	101	99
Minority interest	19	18
Deferred income taxes	112	(25)
Change in risk management assets and liabilities	(129)	140
Changes in certain assets and liabilities		
Receivables	720	43
Inventories	(84)	(187)
Payables	(501)	94
Other	(62)	(121)
Net cash flow provided by operating activities	341	188
Cash flows provided by (used in) investing activities		
Property, plant and equipment expenditures	(190)	(194)
Sale of ownership interest in Saltville Gas Storage Company, LLC	-	66
Other	5	8
Net cash flow used in investing activities	(185)	(120)
Cash flows provided by (used in) financing activities		
Payment of notes payable to Trusts	(150)	-
Payments and borrowings of short-term debt	(81)	11
Dividends paid on common shares	(84)	(72)
Distributions to minority interest	(22)	(19)
Purchase of treasury shares	(26)	-
Issuance of senior notes	175	-
Sale of treasury shares	8	-
Sale of common stock	3	20
Other	3	1
Net cash flow used in financing activities	(174)	(59)
Net (decrease) increase in cash and cash equivalents	(18)	9
Cash and cash equivalents at beginning of period	32	49
Cash and cash equivalents at end of period	$14	$58
Cash paid during the period for		
Interest (net of allowance for funds used during construction)	$78	$62
Income taxes	$33	$48

See Notes to Condensed Consolidated Financial Statements (Unaudited).

AGL RESOURCES INC. AND SUBSIDIARIES
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

Note 1
Accounting Policies and Methods of Application

General

AGL Resources Inc. is an energy services holding company that conducts substantially all of its operations through its subsidiaries. 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).

We have prepared the accompanying unaudited condensed consolidated financial statements under the rules of the Securities and Exchange Commission (SEC). Under such rules and regulations, we have condensed or omitted certain information and notes normally included in financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP). However, the condensed consolidated financial statements reflect all adjustments that are, in the opinion of management, necessary for a fair presentation of our financial results for the interim periods. You should read these condensed consolidated financial statements in conjunction with our consolidated financial statements and related notes included in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005, filed with the SEC on June 1, 2006.

Due to the seasonal nature of our business, our results of operations for the three and nine months ended September 30, 2006 and 2005 and our financial position as of December 31, 2005 and September 30, 2006 and 2005 are not necessarily indicative of the results of operations and financial condition to be expected as of or for any other period.

Basis of Presentation

Our condensed consolidated financial statements include our accounts, the accounts of our majority-owned and controlled subsidiaries and the accounts of variable interest entities for which we are the primary beneficiary. All significant intercompany items have been eliminated in consolidation. Certain amounts from prior periods have been reclassified and revised to conform to the current period presentation. Specifically, $63 million of negative salvage previously presented at December 31, 2005 and September 30, 2005 in accumulated depreciation has been presented in accumulated removal costs for all balance sheet dates presented herein.

We currently own a non-controlling 70% financial interest in SouthStar Energy Services LLC (SouthStar), and Piedmont Natural Gas Company (Piedmont) owns the remaining 30%. Our 70% interest is non-controlling because all significant management decisions require approval by both owners.

We are the primary beneficiary of SouthStar’s activities and have determined that SouthStar is a variable interest entity as defined by the Financial Accounting Standards Board (FASB) Interpretation No. 46, “Consolidation of Variable Interest Entities,” as revised in December 2003 (FIN 46R). We determined that SouthStar was a variable interest entity because our equal voting rights with Piedmont are not proportional to our economic obligation to absorb 75% of any losses or residual returns from SouthStar. In addition, SouthStar obtains substantially all its transportation capacity for delivery of natural gas through our wholly owned subsidiary, Atlanta Gas Light Company (Atlanta Gas Light).

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

Inventories

Sequent Energy Management, L.P. (Sequent) and SouthStar account for their natural gas inventories at the lower of weighted average cost or market. Sequent and SouthStar evaluate the average cost of their natural gas inventories against market prices and determine whether any declines in market prices below the average cost are other than temporary. For any declines considered to be other than temporary, adjustments are recorded to reduce the weighted average cost of the natural gas inventory to market. Consequently, as a result of declining natural gas prices Sequent recorded adjustments of $20 million for the three months, and $33 million for the nine months ended September 30, 2006, against its cost of sales to reduce the value of its inventory to market value. Sequent and SouthStar were not required to make similar adjustments in the same periods last year.

Comprehensive Income

Our comprehensive income includes net income plus other comprehensive income (OCI). This includes other gains and losses affecting shareholders' equity that are excluded from net income under GAAP. Such items consist primarily of unrealized gains and losses on certain derivatives designated as cash flow hedges. The following tables illustrate our OCI activity for the three and nine months ended September 30, 2006 and 2005.

	Three months ended September 30,	
In millions	2006	2005
Cash flow hedges (1):		
Net derivative unrealized gains (losses) arising during the period (net of taxes of $3 in 2006 and $1 in 2005)	$6	$(1)
Less reclassification of realized losses (gains) included in income (net of taxes of $1 in 2006 and $2 in 2005)	1	(3)
Total	$7	$(4)

	Nine months ended September 30,	
In millions	2006	2005
Cash flow hedges (1):		
Net derivative unrealized gains (losses) arising during the period (net of taxes of $6 in 2006 and $1 in 2005)	$12	$(2)
Less reclassification of realized gains included in income (net of taxes of $1 in 2006 and $4 in 2005)	(2)	(6)
Total	$10	$(8)

Earnings per Common Share

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

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

	Three months ended September 30,	
In millions	2006	2005
Denominator for basic earnings per share (1)	77.5	77.5
Assumed exercise of restricted stock, restricted stock units and stock options	0.4	0.6
Denominator for diluted earnings per share	77.9	78.1

(1) Daily weighted-average shares outstanding

	Nine months ended September 30,	
In millions	2006	2005
Denominator for basic earnings per share (1)	77.6	77.2
Assumed exercise of restricted stock, restricted stock units and stock options	0.5	0.6
Denominator for diluted earnings per share	78.1	77.8

(1) Daily weighted-average shares outstanding

Accounting pronouncements issued but not yet adopted

FIN 48 In July 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standard (SFAS) Interpretation No. (FIN) 48, "Accounting for Uncertainty in Income Taxes – an interpretation of SFAS Statement No. 109" (FIN 48).

FIN 48 applies to all "tax positions" accounted for under SFAS No. 109, "Accounting for Income Taxes" (SFAS 109). FIN 48 refers to the term "tax position" as a position taken in a previously filed tax return or a position expected to be taken in a future tax return that is reflected in measuring current or deferred income tax assets and liabilities reported in the financial statements. FIN 48 further clarifies the term “tax position” to include (1) a decision not to file a tax return in a particular jurisdiction for which a return might be required, (2) an allocation or a shift of income between taxing jurisdictions, (3) the characterization of income or a decision to exclude reporting taxable income in a tax return, or (4) a decision to classify a transaction, entity, or other position in a tax return as tax exempt.

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

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

This statement will be effective for us on January 1, 2007 and will require us to record any change in net assets that results from the adoption of FIN 48 as an adjustment to the opening balance of retained earnings. We are evaluating the impact that the adoption of FIN 48 will have on our consolidated results of operations, cash flows and financial position.

SFAS 157 In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements” (SFAS 157). SFAS 157 establishes a framework for measuring fair value and requires expanded disclosures about fair value measurements.

SFAS 157 bases fair value on the price in a transaction between market participants to sell an asset or transfer a liability in the principal or most advantageous market available for the asset or liability. SFAS 157 primarily focuses on the price at which to sell an asset or transfer a liability in order to exit such activity as opposed to the price to purchase the asset or transfer the liability in order to enter such activity.

SFAS 157 will be effective for us on January 1, 2008. All valuation adjustments will be recognized as a cumulative-effect adjustment to the opening balance of retained earnings for the fiscal year in which SFAS 157 is initially applied. We are currently evaluating the impact that SFAS 157 will have on our consolidated results of operations, cash flows and financial position.

SFAS 158 In September 2006, the FASB issued SFAS No. 158, “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans” (SFAS 158). SFAS 158 requires that we recognize all obligations related to defined benefit pensions and other postretirement benefits. This statement will require that we quantify the plan’s funding status as an asset or a liability on our consolidated balance sheets.

SFAS 158 requires that we measure the plan’s assets and obligations that determine our funded status as of the end of the fiscal year. We will also be required to recognize as a component of OCI the changes in funded status that occurred during the year that are not recognized as part of net periodic benefit cost as explained in SFAS No. 87, “Employers’ Accounting for Pensions,” or SFAS No. 106, “Employers’ Accounting for Postretirement Benefits Other Than Pensions.”

We will adopt SFAS 158 on December 31, 2006. We are currently assessing the impact SFAS 158 will have on our consolidated financial statements. Based on the funded status of our defined benefit pension and postretirement benefit plans as of December 31, 2005, (our most recent measurement date) we would report an increase to our OCI of $15 - $20 million, an increase of $15 - $20 million to accrued pension obligations and a reduction of $5 - $10 million to accumulated deferred income taxes. We will finalize these amounts and make the appropriate adjustments for the 2006 activity when we receive a new actuarial report for the year ending December 31, 2006. Based on the range of estimated adjustments through December 31, 2005, we do not expect our adoption of SFAS 158 on December 31, 2006, to have an impact on our earnings.

Note 2
Risk Management

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

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

In September 2006, SouthStar entered into weather derivative contracts as an economic hedge of operating margins in the event of warmer-than-normal weather in the upcoming heating season, primarily from November through March. SouthStar accounts for these contracts using the intrinsic value method under the guidelines of Emerging Issues Task Force 99-02, "Accounting for Weather Derivatives." SouthStar had no weather derivatives outstanding as of September 30, 2005 and December 31, 2005.

There have been no other significant changes to our risk management activities, as described in Note 4 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005.

Note 3
Regulatory Assets and Liabilities

We have recorded regulatory assets and liabilities in our consolidated balance sheets in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." There have been no significant changes to the nature of our regulatory assets and liabilities since December 31, 2005. Our regulatory assets and liabilities at December 31, 2005 are described in Note 5 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005. Our regulatory assets, associated assets, regulatory liabilities, and associated liabilities are summarized in the table below:

In millions	Sept. 30, 2006	Dec. 31, 2005	Sept. 30, 2005
Regulatory assets			
Unrecovered pipeline replacement program (PRP) costs	$284	$303	$355
Unrecovered environmental remediation costs (ERC)	179	196	209
Unrecovered postretirement benefit costs	13	14	14
Unrecovered seasonal rates	10	11	10
Elizabethtown Gas hedging program	20	-	-
Unrecovered purchased gas adjustment	8	8	4
Other	15	10	8
Total regulatory assets	$529	$542	$600
Associated assets			
Elizabethtown Gas hedging program	$-	$17	$43
Total regulatory and associated assets	$529	$559	$643
Regulatory liabilities			
Accumulated removal costs	$160	$156	$155
Deferred purchased gas adjustment	16	40	45
Unamortized investment tax credit	18	19	19
Regulatory tax liability	17	17	13
Elizabethtown Gas hedging program	-	17	43
Other	2	6	7
Total regulatory liabilities	213	255	282
Associated liabilities			
PRP costs	247	265	317
ERC	93	88	94
Elizabethtown Gas hedging program	20	-	-
Total associated liabilities	360	353	411
Total regulatory and associated liabilities	$573	$608	$693

Note 4
Employee Benefit Plans

Pension Benefits We sponsor two tax qualified defined benefit retirement plans for our eligible employees: the AGL Resources Inc. Retirement Plan and the NUI Corporation Retirement Plan. A defined benefit plan specifies the amount of benefits an eligible participant eventually will receive using information about the participant. The following are the combined cost components of our two pension plans for the periods indicated:

	Three months ended September 30,	
In millions	2006	2005
Service cost	$1	$2
Interest cost	5	7
Expected return on plan assets	(7)	(8)
Recognized actuarial loss	2	2
Net cost	$1	$3

	Nine months ended September 30,	
In millions	2006	2005
Service cost	$5	$7
Interest cost	18	20
Expected return on plan assets	(23)	(24)
Net amortization	(1)	(1)
Recognized actuarial loss	6	5
Net cost	$5	$7

Our employees do not contribute to the retirement plans. We fund the plans by contributing at least the minimum amount required by applicable regulations and as recommended by our actuary. However, we may also contribute in excess of the minimum required amount. We calculate the minimum amount of funding using the projected unit credit cost method. We are not required to make any contribution to our pension plans in 2006, but we made a voluntary contribution of $5 million to the AGL Resources Inc. Retirement Plan in October 2006.

Postretirement Benefits We sponsor two defined benefit postretirement health care plans for our eligible employees: the AGL Resources Inc. Postretirement Health Care Plan and the NUI Corporation Postretirement Health Care Plan. Eligibility for these benefits is based on age and years of service. The following are the combined cost components of these two postretirement benefit plans for the periods indicated:

	Three months ended September 30,	
In millions	2006	2005
Service cost	$-	$-
Interest cost	1	1
Expected return on plan assets	(1)	(1)
Prior service cost	(1)	(1)
Net cost	$(1)	$(1)

	Nine months ended September 30,	
In millions	2006	2005
Service cost	$-	$1
Interest cost	4	4
Expected return on plan assets	(3)	(3)
Prior service cost	(3)	(3)
Recognized actuarial loss	1	1
Net cost	$(1)	$-

Note 5
Stock-based Compensation Plans

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

Prior to January 1, 2006, we accounted for our share-based payment transactions in accordance with SFAS No. 123, “Accounting for Stock-Based Compensation,” as amended by SFAS No. 148, “Accounting for Stock-Based Compensation-Transition and Disclosure.” This allowed us to follow Accounting Principles Board (APB) Opinion No. 25, “Accounting for Stock Issued to Employees” (APB 25) and related interpretations in accounting for our stock-based compensation plans.

SFAS 123R requires us to measure and recognize stock-based compensation expense in our financial statements based on the estimated fair value at the date of grant for our share-based awards, which include performance shares and stock options. Performance share awards contain market conditions. Both performance share and stock option awards contain a service condition. In accordance with SFAS 123R, we recognize compensation expense over the requisite service period for:

- awards granted on or after January 1, 2006; and

- unvested awards previously granted and outstanding as of January 1, 2006.

In addition, we estimate forfeitures over the requisite service period when recognizing compensation expense. These estimates are adjusted to the extent that actual forfeitures differ, or are expected to materially differ, from such estimates.

In 2005, we did not record compensation expense related to our stock option grants in our financial statements, which is consistent with the APB 25 requirements. However, at the end of each reporting period, we recorded compensation expense over the requisite service period for our other stock-based and cash unit awards. The following tables provide additional information on compensation costs and income tax benefits related to our compensation awards. We recorded these amounts in our condensed consolidated statements of income for the three and nine months ended September 30, 2006 and 2005.

	Three months ended September 30,	
In millions	2006	2005
Compensation costs	$2	$1
Income tax benefits	1	2

	Nine months ended September 30,	
In millions	2006	2005
Compensation costs	$7	$5
Income tax benefits	2	4

Prior to our adoption of SFAS 123R, benefits of tax deductions in excess of recognized compensation costs were reported as operating cash flows. SFAS 123R requires excess tax benefits to be reported as a financing cash inflow rather than as a reduction of taxes paid. For the nine months ended September 30, 2006, our cash flow used in financing activities included an immaterial amount for benefits of tax deductions in excess of recognized compensation costs. For the same period last year, we included $4 million of such benefits in cash flow provided by operating activities.

If stock-based compensation expense for the three and nine months ended September 30, 2005 had been recorded based on the fair value of the awards at the grant dates consistent with the method prescribed by SFAS 123, which has been superseded by SFAS 123R, our net income and earnings per share for the three and nine months ended September 30, 2005 would have been reduced to the amounts shown in the following table:

In millions, except per share amounts	Three months ended September 30, 2005
Net income, as reported	$15
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	(1)
Pro-forma net income	$14
Earnings per share:	
Basic – as reported	$0.19
Basic – pro-forma	$0.18
Diluted – as reported	$0.19
Diluted – pro-forma	$0.18

In millions, except per share amounts	Nine months ended September 30, 2005
Net income, as reported	$127
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effect	(2)
Pro-forma net income	$125
Earnings per share:	
Basic – as reported	$1.64
Basic – pro-forma	$1.62
Diluted – as reported	$1.62
Diluted – pro-forma	$1.60

Incentive and Nonqualified Stock Options

We grant incentive and nonqualified stock options with a strike price equal to the fair market value on the date of the grant. Stock options generally have a three-year vesting period. As of September 30, 2006, our Board of Directors had authorized 10 million shares to be granted as stock options. Nonqualified options generally become fully exercisable not earlier than six months after the date of grant and generally expire 10 years after the date of grant. Participants realize value from option grants only to the extent that the fair market value of our common stock on the date of exercise of the option exceeds the fair market value of the common stock on the date of the grant. Compensation expense associated with stock options is generally recorded over the option vesting period; however, for unvested options that are granted to employees who are retirement eligible, the remaining compensation expense is recorded in the current period rather than over the remaining vesting period.

As of September 30, 2006, we had $4 million of total unrecognized compensation costs related to stock options. These costs are expected to be recognized over the remaining average requisite service period of approximately 2 years. Cash received from stock option exercises for the nine months ended September 30, 2006 was $9 million, and the income tax benefit from stock option exercises was $2 million. The following tables summarize activity during the nine months ended September 30, 2006 related to grants of stock options for key employees and nonemployee directors.

Stock Options

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)	Aggregate Intrinsic Value (in millions)
Outstanding – December 31, 2005	2,221,245	$27.79	6.8	
Granted	906,898	35.79	9.4	
Exercised	(367,305)	24.84	5.2	
Forfeited	(261,418)	34.91	8.7	
Outstanding – September 30, 2006	2,499,420	$30.39	7.4	$15
Exercisable – September 30, 2006	1,178,163	$25.20	5.4	$13

Unvested Stock Options

	Number of Unvested Options	Weighted Average Exercise Price	Weighted Average Remaining Vesting Period (in years)	Weighted Average Fair Value
Outstanding – December 31, 2005	945,556	$33.64	2.1	$4.72
Granted	906,898	35.79	2.4	4.79
Forfeited	(252,099)	34.96	1.7	4.96
Vested	(279,098)	32.91	-	4.55
Outstanding – September 30, 2006	1,321,257	$35.02	2.0	$4.76

In accordance with the fair value method of determining compensation expense, we use the Black-Scholes option pricing model. Below are the ranges for per share value and information about the underlying assumptions used in developing the grant date value for each of the grants made during the nine months ended September 30, 2006 and 2005.

	Nine months ended September 30, 2006	2005
Expected life (years)	7	7
Risk-free interest rate % (1)	4.4 - 5.1	3.9 - 4.2
Expected volatility % (2)	15.0 - 15.9	17.1-17.3
Dividend yield % (4)	3.8 – 4.2	3.2 - 3.8
Fair value of options granted (3)	$4.64 - $5.76	$5.16 - $6.19

(1) US Treasury constant maturity – 7 years
(2) Volatility is measured over 7 years, the expected life of the options, Weighted average for the nine months ended September 30, 2006 and 2005 were 15.8% and 17.2%, respectively.
(3) Represents per share value.
(4) Weighted average dividend yields for the nine months ended September 30, 2006 and 2005 were 4.1% and 3.4%, respectively

Intrinsic value for options is defined as the difference between the current market value and the grant price. Total intrinsic value of options exercised during the nine months ended September 30, 2006 and 2005 was $4 million and $10 million, respectively. We use shares purchased under our share repurchase program to satisfy share-based exercises to the extent that repurchased shares are available. Otherwise, we issue new shares from our authorized common stock.

Stock and Restricted Stock Awards

Stock Awards Under the 1996 Non-Employee Directors Equity Compensation Plan (Directors Plan), each non-employee director receives an annual retainer. The amount and form of the annual retainer are fixed by resolution of the Board of Directors. Effective in January 2006, the annual retainer was increased from $60,000 to $90,000, of which (1) $30,000 is payable in cash or, at the election of each director, in shares of our common stock or is deferred and invested in common stock equivalents under the 1998 Common Stock Equivalent Plan for Non-Employee Directors (CSE Plan) and (2) $60,000 is payable, at the election of each director, in shares of our common stock or deferred under the CSE Plan. Upon initial election to our Board of Directors, each non-employee director receives 1,000 shares of common stock as of the first day of his or her service. Shares issued under the Directors Plan are 100% vested and nonforfeitable as of the date of grant.

Restricted Stock Awards In general, we refer to an award of our common stock that is subject to time-based vesting or achievement of performance measures as "restricted stock." Restricted stock awards are subject to certain transfer restrictions and forfeiture upon termination of employment. The following table summarizes activity during the nine months ended September 30, 2006 related to restricted stock awards for our key employees.

Restricted Stock Awards	Shares of Restricted Stock	Weighted Average Remaining Vesting Period (in years)	Weighted Average Fair Value
Outstanding – December 31, 2005	120,728	2.3	$34.33
Issued	193,395	2.4	35.63
Forfeited	(30,466)	1.8	34.44
Vested	(34,597)	-	34.37
Outstanding – September 30, 2006	249,060	2.2	$35.32

Performance Units A performance unit is an award of the right to receive either (1) shares of our common stock or (2) cash, subject in each case to the achievement of certain pre-established performance criteria. Performance units are subject to certain transfer restrictions and forfeiture upon termination of employment. In the first quarter of 2006, we granted restricted stock units and performance units to a select group of officers as described below.

Restricted Stock Units A restricted stock unit is an award that represents the opportunity to receive a specified number of shares of our common stock, subject to the achievement of certain pre-established performance criteria.

In February 2006, we granted to a select group of officers restricted stock units for a total of 64,700 shares of common stock under the Long-Term Incentive Plan (1999) (LTIP), 61,800 of which were outstanding as of September 30, 2006. These restricted stock units have a 12-month performance measurement period and a performance measure that relates to a basic earnings per share goal.

Performance Cash Units A performance cash unit is an award that represents the opportunity to receive a cash award, subject to the achievement of certain pre-established performance criteria.

In January 2006, we granted performance cash units to a select group of officers under the LTIP. The performance cash units represent a maximum aggregate payout of $2 million. The performance cash units have a 36-month performance measurement period and a performance measure that relates to our average annual growth in basic earnings per share plus the average dividend yield. As of September 30, 2006, we had recorded a liability of less than $1 million for these performance cash units.

Stock Appreciation Rights (SARs) SARs are awards payable in cash, having an exercise price equal to the fair market value of our common stock on the date of grant. SARs generally become fully exercisable not earlier than 12 months after the date of grant and generally expire six years after that date. Participants realize value from SAR grants only to the extent that the fair market value of our common stock on the date of exercise of the SAR exceeds the fair market value of the common stock on the date of the grant. At September 30, 2006, we had approximately 27,000 SARs outstanding.

Note 6
Common Shareholders' Equity

Share Repurchase Program In February 2006, our Board of Directors authorized a plan to purchase up to eight million shares of our outstanding common stock over a five-year period. These purchases are intended principally to offset share issuances under our employee and non-employee director incentive compensation plans and our dividend reinvestment and stock purchase plans. Stock purchases under this program may be made in the open market or in private transactions at times and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we will purchase, and we can terminate or limit the program at any time. We will hold the purchased shares as treasury shares. During the nine months ended September 30, 2006, we repurchased 730,500 shares at a weighted average price of $36.19.

Note 7
Debt

Our issuance of long-term and short-term debt, including various forms of securities, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Our financing consists of the short and long-term debt indicated in the following table.

			Outstanding as of:		
Dollars in millions	Year(s) due	Int. rate (1)	Sept.30, 2006	Dec. 31, 2005	Sept.30, 2005
Short-term debt					
Commercial paper	2006	5.4% (2)	$420	$485	$318
Sequent lines of credit	2006 - 2007	5.7% (3)	1	-	25
Pivotal Utility Holdings, Inc. line of credit	2006	5.8% (4)	19	-	-
Capital leases	2006	4.9%	1	1	1
SouthStar line of credit	2006	-	-	36	-
Total short-term debt		**5.4%** (5)	**$441**	**$522**	**$344**
Long-term debt					
Senior notes	2011-2034	4.5 – 7.1%	$1,150	$975	$975
Medium-term notes	2012-2027	6.6 – 9.1%	208	208	208
Gas facility revenue bonds, net of unamortized issuance costs	2022-2033	3.5 – 5.7%	199	199	199
Notes payable to Trusts	2037	8.2%	77	232	232
Capital leases	2013	4.9%	6	6	7
Interest rate swaps	2011	9.0%	(6)	(5)	(5)
Total long-term debt		**6.1%** (5)	**$1,634**	**$1,615**	**$1,616**
Total short-term and long-term debt		**6.0%** (5)	**$2,075**	**$2,137**	**$1,960**

(1) As of September 30, 2006.
(2) The daily weighted average rate was 5.0% for the nine months ended September 30, 2006.
(3) The daily weighted average rate was 5.5% for the nine months ended September 30, 2006.
(4) The daily weighted average rate was 5.6% for the nine months ended September 30, 2006.
(5) Weighted average interest rate, including interest rate swaps if applicable and excluding debt issuance and other financing related costs.

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

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

Long-term debt In May 2001, AGL Capital Trust II (Trust) issued and sold $150 million of 8.00% capital securities and used the proceeds to purchase $150 million principal amount of 8.00% junior subordinated deferrable interest debentures from us. In May 2006, we used the proceeds from the sale of commercial paper to redeem the $150 million of junior subordinated debentures and to pay a $5 million note representing our investment in the Trust, previously included in notes payable to Trusts. In June 2006, we issued $175 million of 10-year senior notes at an interest rate of 6.375% and used the net proceeds of $174 million to repay the commercial paper.

In the third quarter of 2005 and the second quarter of 2006, in anticipation of our $175 million senior notes offering in June 2006, we entered into treasury lock derivative agreements to hedge our exposure to increases in interest rates. We received an $11 million settlement payment from our counterparties, which we will amortize over the next 10 years through interest expense. These derivatives reduced the annual interest rate on our 6.375% senior notes by approximately 60 basis points.

Note 8
Commitments and Contingencies

Contractual Obligations and Commitments We have incurred various contractual obligations and financial commitments in the normal course of our operations and financing activities. Contractual obligations include future cash payments required under existing contractual arrangements, such as debt and lease agreements. These obligations result from both general financing activities and from commercial arrangements that are directly supported by related revenue-producing activities. There were no significant changes to our contractual obligations described in Note 10 to our Consolidated Financial Statements in Item 8 of our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur. This covers financial guarantees and includes the nature of the guarantee and the maximum potential amount of future payments that are required of us as the guarantor. The following table illustrates our contingent financial commitments as of September 30, 2006.

		Commitments due before Dec. 31,	
In millions	Total	2006	2007 & thereafter
Standby letters of credit and performance and surety bonds	$23	$11	$12

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

Columbia Gas Transmission In January 2004, Virginia Natural Gas, Inc. (Virginia Natural Gas) filed a complaint with the Federal Energy Regulatory Commission (FERC) against Columbia Gas Transmission (Columbia), a subsidiary of NiSource Inc. Among other things, the complaint alleged that, beginning in January 2003, Virginia Natural Gas experienced a number of critical service problems with Columbia that interrupted deliveries of natural gas to some industrial customers and increased prices paid by Virginia Natural Gas' customers. Virginia Natural Gas was seeking approximately $37 million in damages, the majority of which would be distributed to its customers. In September 2006, Virginia Natural Gas and Columbia reached a settlement. The terms of the settlement are confidential and did not have a material impact on our results of operations, cash flows and financial position. The majority of the benefits under the settlement will be passed through to Virginia Natural Gas customers as reductions in the cost of natural gas.

State of Louisiana In September 2006, Pivotal Jefferson Island Storage & Hub, LLC, (Pivotal Jefferson Island) filed suit against the State of Louisiana to maintain its lease to complete an ongoing natural gas storage expansion project in Louisiana. The project would add two salt dome storage caverns under Lake Peigneur to the two caverns currently owned and operated by Pivotal Jefferson Island.

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

In its suit Pivotal Jefferson Island alleges that the DNR accepted all leasehold payments without reservation and never provided Pivotal Jefferson Island with notice and opportunity to cure as required by State law. As to the second basis for termination, the suit contends that Pivotal Jefferson Island's lease with the State of Louisiana was amended in 2004 so that mining operations are no longer required to maintain the lease. We continue to seek resolution of this dispute and have yet to serve the complaint formally on the State. Service of the complaint would formally commence the litigation process, including discovery and scheduling of a hearing on the issues identified in the complaint. It is not possible at this time to predict whether the dispute can be settled or, if not, what the results of the litigation would be.

Note 9
Segment Information

Our four operating segments are:

- Distribution operations, which consist primarily of:
  - Atlanta Gas Light
  - Elizabethtown Gas
  - Virginia Natural Gas
  - Florida City Gas
  - Chattanooga Gas Company (Chattanooga Gas)
  - Elkton Gas
- Retail energy operations, which consist primarily of SouthStar
- Wholesale services, which consist primarily of Sequent
- Energy investments, which consist primarily of:
  - Pivotal Jefferson Island
  - Pivotal Propane of Virginia, Inc. (Pivotal Propane)
  - AGL Networks, LLC (AGL Networks)

We treat corporate, our fifth segment, as a non-operating business segment, and it includes AGL Resources Inc., AGL Services Company, investments in nonregulated financing subsidiaries and the effect of intercompany eliminations. We eliminated intercompany sales for the three and nine months ended September 30, 2006 and 2005 from our condensed consolidated statements of income.

We evaluate segment performance based primarily on the non-GAAP measure of earnings before interest and taxes (EBIT), which includes the effects of corporate expense allocations. EBIT includes operating income, other income and minority interest. Items that we do not include in EBIT are financing costs, including interest and debt expense and income taxes. We evaluate 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 we believe is directly relevant to the operational performance of those operations.

You should not consider EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our EBIT may not be comparable to a similarly titled measure of another company. The reconciliations of EBIT to operating income and net income for the three and nine months ended September 30, 2006 and 2005 are presented below.

	Three months ended September 30,	
In millions	2006	2005
Operating revenues	$434	$393
Operating expenses	344	339
Operating income	90	54
Minority interest	-	(2)
EBIT	90	52
Interest expense	32	27
Earnings before income taxes	58	25
Income taxes	22	10
Net income	$36	$15

	Nine months ended September 30,	
In millions	2006	2005
Operating revenues	$1,914	$1,736
Operating expenses	1,536	1,435
Operating income	378	301
Other (expense) income	(2)	2
Minority interest	(19)	(18)
EBIT	357	285
Interest expense	91	79
Earnings before income taxes	266	206
Income taxes	101	79
Net income	$165	$127

Summarized income statement information and property, plant and equipment expenditures as of and for the three and nine months ended September 30, 2006 and 2005 by segment are shown in the following tables:

Three months ended September 30, 2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$218	$132	$74	$10	$-	$434
Intercompany revenues (1)	35	-	-	-	(35)	-
Total operating revenues	253	132	74	10	(35)	434
Operating expenses						
Cost of gas	86	119	20	-	(35)	190
Operation and maintenance	82	14	13	5	(3)	111
Depreciation and amortization	28	1	1	2	1	33
Taxes other than income taxes	7	1	-	-	2	10
Total operating expenses	203	135	34	7	(35)	344
Operating income (loss)	50	(3)	40	3	-	90
Other income (expense)	-	1	-	-	(1)	-
EBIT	$50	$(2)	$40	$3	$(1)	$90
Property, plant and equipment expenditures	$48	$3	$1	$13	$12	$77

Three months ended September 30, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$225	$153	$1	$14	$-	$393
Intercompany revenues (1)	38	-	-	-	(38)	-
Total operating revenues	263	153	1	14	(38)	393
Operating expenses						
Cost of gas	95	129	-	4	(37)	191
Operation and maintenance	85	13	6	4	(2)	106
Depreciation and amortization	28	1	1	1	2	33
Taxes other than income taxes	7	1	-	-	1	9
Total operating expenses	215	144	7	9	(36)	339
Operating income (loss)	48	9	(6)	5	(2)	54
Other income (expense)	1	-	-	-	(1)	-
Minority interest	-	(2)	-	-	-	(2)
EBIT	$49	$7	$(6)	$5	$(3)	$52
Property, plant and equipment expenditures	$51	$-	$-	$1	$12	$64

(1) Wholesale services total operating revenues include intercompany revenues of $110 million and $201 million for the three months ended September 30, 2006 and 2005, respectively.

Nine months ended September 30, 2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,068	$675	$141	$30	$-	$1,914
Intercompany revenues (1)	118	-	-	-	(118)	-
Total operating revenues	1,186	675	141	30	(118)	1,914
Operating expenses						
Cost of gas	594	551	33	4	(118)	1,064
Operation and maintenance	251	48	33	14	(5)	341
Depreciation and amortization	86	3	2	4	6	101
Taxes other than income taxes	24	1	-	1	4	30
Total operating expenses	955	603	68	23	(113)	1,536
Operating income (loss)	231	72	73	7	(5)	378
Other income (expense)	1	(1)	-	-	(2)	(2)
Minority interest	-	(19)	-	-	-	(19)
EBIT	$232	$52	$73	$7	$(7)	$357
Property, plant and equipment expenditures	$126	$6	$2	$20	$36	$190

Nine months ended September 30, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations	Consolidated AGL Resources
Operating revenues from external parties	$1,045	$627	$21	$43	$-	$1,736
Intercompany revenues (1)	145	-	-	-	(145)	-
Total operating revenues	1,190	627	21	43	(145)	1,736
Operating expenses						
Cost of gas	590	513	-	12	(143)	972
Operation and maintenance	269	40	19	12	(6)	334
Depreciation and amortization	85	2	2	4	6	99
Taxes other than income taxes	24	1	-	1	4	30
Total operating expenses	968	556	21	29	(139)	1,435
Operating income (loss)	222	71	-	14	(6)	301
Other income (expense)	2	-	-	1	(1)	2
Minority interest	-	(18)	-	-	-	(18)
EBIT	$224	$53	$-	$15	$(7)	$285
Property, plant and equipment expenditures	$160	$2	$1	$7	$24	$194

(1) Wholesale services total operating revenues include intercompany revenues of $404 million and $450 million for the nine months ended September 30, 2006 and 2005, respectively.

Balance sheet information as of September 30, 2006 and 2005 and December 31, 2005 by segment is shown in the following tables:

As of September 30, 2006

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (2)	Consolidated AGL Resources
Goodwill	$411	$-	$-	$14	$-	$425
Identifiable and total assets (1)	$4,573	$226	$715	$374	$(48)	$5,840

As of December 31, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (2)	Consolidated AGL Resources
Goodwill	$406	$-	$-	$14	$-	$420
Identifiable and total assets (1)	$4,780	$343	$1,058	$350	$(218)	$6,313

As of September 30, 2005

In millions	Distribution operations	Retail energy operations	Wholesale services	Energy investments	Corporate and intercompany eliminations (2)	Consolidated AGL Resources
Goodwill	$391	$-	$-	$14	$-	$405
Identifiable and total assets (1)	$4,660	$228	$1,108	$348	$(194)	$6,150

(1) Identifiable assets are those assets used in each segment's operations.
(2) Our corporate segment's assets consist primarily of intercompany eliminations, cash and cash equivalents and property, plant and equipment.

ITEM 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

FORWARD-LOOKING STATEMENTS

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

Forward-looking statements involve matters that are not historical facts, and because these statements involve anticipated events or conditions, forward-looking statements often include words such as "anticipate", "assume", “believe”, "can", "could", "estimate", "expect", "forecast", "future", "indicate", "intend", "may", “outlook”, "plan", "predict", "project”, "seek", "should", "target", "will", "would", or similar expressions. Our expectations are not guarantees and are based on currently available competitive, financial and economic data along with our operating plans. While we believe that our expectations are reasonable in view of the currently available information, our expectations are subject to future events, risks and uncertainties, and there are several factors - many beyond our control - that could cause our results to differ significantly from our expectations.

Such events, risks and uncertainties include, but are not limited to, changes in price, supply and demand for natural gas and related products; the impact of changes in state and federal legislation and regulation; actions taken by government agencies on rates and other matters; concentration of credit risk; utility and energy industry consolidation; the impact of acquisitions and divestitures; direct or indirect effects on our business, financial condition or liquidity resulting from a change in our credit ratings or the credit ratings of our counterparties or competitors; interest rate fluctuations; financial market conditions and general economic conditions; uncertainties about environmental issues and the related impact of such issues; the impact of changes in weather on the temperature-sensitive portions of our business; the impact of natural disasters such as hurricanes on the supply and price of natural gas; acts of war or terrorism; and other factors that are described in detail in our filings with the SEC.

We caution readers that, in addition to the important factors described elsewhere in this report, the factors set forth in “Risk Factors” in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations” of our Annual Report on Form 10-K, as amended on June 1, 2006, for the year ended December 31, 2005, among others, could cause our business, results of operations or financial condition in 2006 and thereafter to differ significantly from those expressed in any forward-looking statements. There also may be other factors that we cannot anticipate or that are not described in our Form 10-K, as amended, or in this report that could cause results to differ significantly from our expectations.

Forward-looking statements are only as of the date they are made, and we do not update these statements to reflect subsequent circumstances or events.

Overview

We are a Fortune 1000 energy services holding company whose principal business is the distribution of natural gas in six states - Florida, Georgia, Maryland, New Jersey, Tennessee and Virginia. Our six utilities serve approximately 2.3 million end-use customers, making us the largest distributor of natural gas in the southeastern and mid-Atlantic regions of the United States based on customer count. We also are involved in various related businesses, including retail natural gas marketing to end-use customers primarily in Georgia; natural gas asset management and related logistics activities for our own utilities as well as for other nonaffiliated companies; natural gas storage and related arbitrage activities; operation of high-deliverability underground natural gas storage assets; and construction and operation of telecommunications conduit and fiber infrastructure within selected metropolitan areas. We manage these businesses through four operating segments – distribution operations, retail energy operations, wholesale services and energy investments – and a nonoperating corporate segment.

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

Regulatory Environment

In August 2005, the Energy Policy Act of 2005 (Energy Act) was enacted. The Energy Act authorized, among other things, the repeal of the Public Utility Holding Company Act of 1935, as amended (PUHCA). The effective date of the PUHCA repeal was February 8, 2006. The Energy Act gives the Federal Energy Regulatory Commission (FERC) increased authority over utility merger and acquisition activity, removes `many of the geographic and structural restrictions on the ownership of public utilities and eliminates certain regulatory burdens. Some of the SEC reporting requirements, financing authorizations and affiliate relationship approvals that previously applied to us under the PUHCA were replaced by the requirements of the Energy Act. In addition, the Energy Act requires a public utility holding company to maintain its books and records and make them available to the FERC and to comply with certain reporting requirements.

The FERC may exempt a class of entities or class of transactions if the FERC finds that they are not relevant to the jurisdictional rate of a public utility or natural gas company. In February 2006, we requested exemption from the FERC, and in April 2006 our exemption from the regulations and reporting requirements under the Energy Act became effective.

Results of Operations

AGL Resources

Customer Natural Gas Demand During last year's heating season, we experienced declines in per-household natural gas use, resulting in operating margin erosion. These declines were largely due to warmer weather – which was on average 11% warmer than in the prior year – and historically higher natural gas prices. The higher natural gas prices resulted in an average 34% increase in our residential customers' natural gas bills, and were primarily the result of market concerns about the sufficiency of the supply of natural gas due to disruptions in the availability of natural gas supplies resulting from hurricanes Katrina and Rita in 2005, and other factors.

Additionally, our underlying business of supplying natural gas to retail customers continues to be negatively impacted by the addition of newer, more energy-efficient housing and efficiency improvements in natural gas appliances. These declines are somewhat offset by the growing trend for larger homes that require more energy to heat despite the use of more efficient appliances.

In the nine months ended September 30, 2006, these factors also impacted our earnings before interest and taxes (EBIT) as a result of higher expenses that were incurred for bad debt, as well as lower volumes of natural gas deliveries to our customers as a result of customer conservation.

Currently natural gas prices are approximately 38% lower than last year and are expected to be lower during the upcoming heating season primarily from November through March. These lower natural gas prices may ease the impact of conservation experienced during the prior heating season and could result in a return to normalized consumption. As a result, we would expect that our operating margins and EBIT at would be positively impacted relative to what we have experienced thus far during 2006.

Seasonality The operating revenues and EBIT of our distribution operations, retail energy operations and wholesale services segments are seasonal. During the heating season natural gas usage and operating revenues are higher because generally more customers are connected to our distribution systems and because natural gas usage is higher in periods of colder weather than in periods of warmer weather. However, our base operating expenses, excluding cost of gas, interest expense and certain incentive compensation costs, are incurred relatively equally over any given year. Thus, our operating results vary significantly from quarter to quarter as a result of seasonality.

Seasonality also affects the comparison of certain balance sheet items such as receivables, inventories and short-term debt across reporting periods. Accordingly, we have presented the condensed consolidated balance sheet as of September 30, 2005 to provide comparisons of these items to December 31, 2005 and September 30, 2006.

Hedging Changes in commodity prices subject a significant portion of our operations to earnings variability. Our nonutility businesses principally use physical and financial arrangements to economically hedge the risks associated with both seasonal fluctuations in market conditions and changing commodity prices. In addition, because these economic hedges may not qualify, or are not designed, for hedge accounting treatment, our reported earnings for the wholesale services and retail energy operations segments reflect changes in the fair values of certain derivatives. These values may change significantly from period to period and are reflected as mark-to-market adjustments within our operating margin.

Elizabethtown Gas utilizes certain derivatives in accordance with a directive from the New Jersey Board of Public Utilities (NJBPU) to create a hedging program to hedge the impact of market fluctuations in natural gas prices. These derivative products are marked to market value each reporting period. In accordance with regulatory requirements, realized gains and losses related to these derivatives are reflected in purchased gas costs and ultimately included in billings to customers. Unrealized gains and losses are reflected as a regulatory asset (loss) or liability (gain), as appropriate, in our consolidated balance sheets.

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

Operating Margin and EBIT We evaluate the performance of our operating segments using the measures of operating margin and EBIT.

We believe operating margin is a better indicator than revenues for the contribution resulting from customer growth in our distribution operations segment since the cost of gas can vary significantly and is generally passed directly to our customers. We also consider operating margin to be a better indicator in our retail energy operations, wholesale services and energy investments segments since it is a direct measure of gross profit before overhead costs. We believe EBIT is a useful measurement of our operating segments’ performance because it provides information that can be used to evaluate the effectiveness of our businesses from an operational perspective, exclusive of the costs to finance those activities and exclusive of income taxes, neither of which is directly relevant to the operating performance of those businesses.

Our operating margin and EBIT are not measures that are considered to be calculated in accordance with accounting principles generally accepted in the United States of America (GAAP). You should not consider operating margin or EBIT an alternative to, or a more meaningful indicator of, our operating performance than operating income or net income as determined in accordance with GAAP. In addition, our operating margin or EBIT measures may not be comparable to similarly titled measures of other companies.

Third quarter 2006 compared to third quarter 2005

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the three months ended September 30, 2006 and 2005.

In millions, except per share amounts	Three months ended September 30, 2006	2005	Change
Operating revenues	$434	$393	$41
Cost of gas	190	191	(1)
Operating margin	244	202	42
Operating expenses	154	148	6
Operating income	90	54	36
Minority interest	-	(2)	2
EBIT	90	52	38
Interest expense	32	27	5
Earnings before income taxes	58	25	33
Income taxes	22	10	12
Net income	$36	$15	$21
Earnings per common share			
Basic	$0.46	$0.19	$0.27
Diluted	$0.46	$0.19	$0.27
Weighted average number of common shares outstanding			
Basic	77.5	77.5	-
Diluted	77.9	78.1	(0.2)

Segment information Operating revenues, operating margin and EBIT information for each of our segments are contained in the following table for the three months ended September 30, 2006 and 2005:

In millions	Three months ended September 30, Operating revenues	Operating margin	EBIT
2006			
Distribution operations	$253	$167	$50
Retail energy operations	132	13	(2)
Wholesale services	74	54	40
Energy investments	10	10	3
Corporate (1)	(35)	-	(1)
Consolidated	$434	$244	$90
2005			
Distribution operations	$263	$168	$49
Retail energy operations	153	24	7
Wholesale services	1	1	(6)
Energy investments	14	10	5
Corporate (1)	(38)	(1)	(3)
Consolidated	$393	$202	$52

(1) Includes intercompany eliminations

EBIT The increase in the third quarter EBIT of $38 million, or 73%, was driven primarily by the wholesale services segment's performance, which is a result of the acceleration, from an accounting standpoint, of some of its future anticipated storage profits into the third quarter as New York Mercantile Exchange (NYMEX) prices declined significantly, partially offset by additional costs to reduce gas inventory values to market. In contrast, the NYMEX price increases experienced during the third quarter of 2005 had the opposite effect. The original economics of the storage transactions are essentially unaffected by these interim changes in market prices.

The distribution operations segment's EBIT increased $1 million in the third quarter compared to last year. The retail energy operation segment's EBIT was down $9 million largely as a result of hedges that were put in place to reduce exposure to higher natural gas prices. In 2006, these hedges experienced no gains as natural gas prices were generally falling during the period. This was due to a more volatile market and higher natural gas prices in 2005. In addition, the retail energy operations segment's interruptible margins were also lower in the third quarter of 2006 compared to 2005, due to the capture of margin opportunities in the third quarter of 2005 related to peaking sales during curtailed customer use during the hurricane activity.

Operating Margin Our operating margin increased $42 million, or 21%, from the same period last year. The following table indicates the significant changes in our operating margin:

In millions	
Operating margin for third quarter 2005	$202
Net change in the fair value of hedges at wholesale services	95
Wholesale services commercial activities	(22)
Inventory lower of cost or market adjustments	(20)
Reduced operating margins at retail energy operations	(11)
Operating margin for third quarter 2006	$244

Wholesale services experienced a net change of $95 million due to movements in hedge fair values on a quarter-over-quarter comparison, comprised primarily of $38 million of storage hedge gains in the third quarter of 2006, compared to the recognition of $46 million of storage hedge losses in the third quarter of 2005. Adding to the storage hedge gains was the recognition of $11 million of gains associated with the financial instruments used to hedge its transportation capacity in the third quarter of 2006. Additionally, as a result of decreasing NYMEX prices, the wholesale services segment recorded a charge of $20 million at certain storage locations in order to reduce the carrying value of its natural gas inventory to the lower of cost or current market prices (LOCOM).

Commercial activities for the wholesale services segment were lower by $22 million. While the segment experienced strong performance in the third quarter of 2006 due to hot weather and advantageous storage opportunities, the third quarter of 2005 produced greater margins due to the unusually high levels of natural gas market volatility resulting from hurricane activity in the Gulf of Mexico.

The $11 million decrease in operating margins at our retail energy operations segment was due to a net $6 million decrease of gains on its risk management derivatives. Additionally, the decrease includes approximately $5 million of decreased operating margin from higher interruptible margins in the third quarter of 2005 due to peaking sales during curtailments and slightly lower unit margins in 2006, offset by higher retail price spreads.

Operating Expenses Our operating expenses increased $6 million, or 4%, from the same period last year. The following table sets forth the significant changes in our operating expenses:

In millions	
Operating expenses for third quarter 2005	$148
Increased incentive compensation at wholesale services	7
Reduced costs from 2005 restructuring in distribution operations	(2)
Other	1
Operating expenses for third quarter 2006	$154

The wholesale services segment recorded $7 million of additional incentive compensation primarily as a result of its increased EBIT. This was offset by a $2 million reduction in costs related to our 2005 workforce and facilities restructuring at the distribution operations segment.

Interest Expense The increase in interest expense of $5 million, or 19%, was due primarily to higher average debt balances and higher short-term interest rates. Average debt balances increased by $227 million as shown in the table below. This was due primarily to higher inventory balances during 2006 resulting from higher balances of gas inventory stored for marketers by Atlanta Gas Light and higher gas inventory levels at Sequent relative to the prior year.

	Three months ended September 30,		
Dollars in millions	2006	2005	Change
Average debt outstanding (1)	$2,079	$1,852	$227
Average rate	5.9%	5.8%	0.1%

(1) Daily average of all outstanding debt.

Income Taxes The increase in income tax expense of $12 million, or 120%, for 2006 compared to 2005 was primarily due to higher pre-tax income for the three months ended September 30, 2006.

Nine months 2006 compared to nine months 2005

The following table sets forth a reconciliation of our operating margin and EBIT to our operating income and net income, together with other consolidated financial information for the nine months ended September 30, 2006 and 2005.

In millions, except per share amounts	Nine months ended September 30, 2006	2005	Change
Operating revenues	$1,914	$1,736	$178
Cost of gas	1,064	972	92
Operating margin	850	764	86
Operating expenses	472	463	9
Operating income	378	301	77
Other (expense) income	(2)	2	(4)
Minority interest	(19)	(18)	(1)
EBIT	357	285	72
Interest expense	91	79	12
Earnings before income taxes	266	206	60
Income taxes	101	79	22
Net income	$165	$127	$38
Earnings per common share			
Basic	$2.13	$1.64	$0.49
Diluted	$2.12	$1.62	$0.50
Weighted average number of common shares outstanding			
Basic	77.6	77.2	0.4
Diluted	78.1	77.8	0.3

Segment information Operating revenues, operating margin and EBIT information for each of our segments are contained in the following table for the nine months ended September 30, 2006 and 2005:

In millions	Nine months ended September 30, Operating revenues	Operating margin	EBIT
2006			
Distribution operations	$1,186	$592	$232
Retail energy operations	675	124	52
Wholesale services	141	108	73
Energy investments	30	26	7
Corporate (1)	(118)	-	(7)
Consolidated	$1,914	$850	$357
2005			
Distribution operations	$1,190	$600	$224
Retail energy operations	627	114	53
Wholesale services	21	21	-
Energy investments	43	31	15
Corporate (1)	(145)	(2)	(7)
Consolidated	$1,736	$764	$285

(1) Includes intercompany eliminations

EBIT The increase in EBIT of $72 million, or 25%, was primarily the result of increases at the wholesale services and distribution operations segments. Wholesale services' EBIT improvement of $73 million reflects the acceleration of economic value into the first nine months of 2006, as NYMEX prices declined significantly. In contrast, the NYMEX price increases experienced during 2005 had the opposite effect.

In the distribution operations segment, EBIT improved by $8 million, with declines in its operating margins of $8 million offset by reduced operating expenses of $17 million. Our retail energy operations segment's EBIT was relatively flat compared to last year. The energy investments segment's EBIT was down $8 million primarily due to the loss of EBIT contributions from the sale in 2005 of certain assets that were originally acquired with the 2004 acquisition of NUI Corporation (NUI).

Operating Margin Our operating margin increased $86 million, or 11%, from the same period last year. The following table indicates the significant changes in our operating margin:

In millions	
Operating margin for nine months 2005	$764
Net change in the fair value of hedges at wholesale services	109
Wholesale services commercial activities	11
Inventory lower of cost or market adjustments	(33)
Improved operating margins at retail energy operations	10
Lower operating margins at distribution operations utilities	(8)
Loss of margin from energy investment assets sold in 2005	(8)
Other	5
Operating margin for nine months 2006	$850

Forward NYMEX prices decreased during 2006, especially in the third quarter. This resulted in the wholesale services segment recognizing $49 million of storage hedge gains in the first nine months of 2006, compared to the recognition of $49 million of storage hedge losses in the first nine months of 2005. In addition, wholesale services recognized $11 million in gains associated with the financial instruments used to hedge its transportation capacity. Consequently, wholesale services experienced a net change of $109 million from its hedging activities for the nine months ended September 30, 2006, compared to last year.

The results of the wholesale services segment also reflect improved commercial activities of approximately $11 million. Sequent was able to capture higher seasonal storage margins in 2006 and additional operating margin opportunities brought on by higher temperatures during the late summer months. This offset the lower operating margins resulting from the milder weather experienced earlier in the year.

As a result of decreasing NYMEX prices, the wholesale services segment evaluated the weighted average cost of its natural gas inventory and recorded LOCOM adjustments totaling $33 million during the nine months ended September 30, 2006.

We experienced increased operating margins at our retail energy operations segment of $10 million as unit margins were higher than last year. The increased unit margins in 2006 reflected a lower gas cost resulting primarily from effective commodity risk management through optimization of storage and transportation assets of $18 million. Our unit margins were further impacted by higher retail spreads offset by lower throughput in 2006 as compared to 2005, a net $8 million decrease. Throughput was lower due in part to weather that was 6% warmer than last year, customer conservation and lower interruptible margins.

The distribution operations segment's operating margin decreased $8 million. This includes a $3 million decrease from discontinuation of the appliance businesses in Florida and New Jersey in late 2005 and $8 million of decreased retail operating margins at Elizabethtown Gas, Virginia Natural Gas, Florida City Gas and Chattanooga Gas. These decreases were offset by a net increase in Atlanta Gas Light's operating margin of $3 million primarily from gas storage carrying charges and pipeline replacement program revenue, offset by the Georgia Public Service Commission's June 2005 Rate Order.

Our operating margin decreased $8 million due to the loss of contributions of certain assets we acquired with the 2004 acquisition of NUI and included in our energy investments segment, but later sold in 2005.

Operating Expenses Our operating expenses increased $9 million, or 2%, from the same period last year. The following table sets forth the significant components of operating expenses:

In millions	
Operating expenses for nine months 2005	$463
Increased incentive compensation at wholesale services	13
Increased bad debt expenses	6
2005 restructuring in distribution operations	(14)
Lower expenses resulting from assets sold in 2005	(6)
Other	10
Operating expenses for nine months 2006	$472

The wholesale services segment recorded $13 million of additional payroll due to increased number of employees to support growth and increased incentive compensation, which is generally based on Sequent's operating performance. Our bad debt expense for the nine months ended September 30, 2006 increased over last year primarily in our retail energy operations segment. The retail energy operation's bad debt was $10 million, a $5 million increase from the same period last year, driven by an increase in the amount of accounts receivable balances past due more than 60 days largely due to SouthStar's offer of payment arrangements to customers in an effort to assist customers with their payment of higher natural gas bills.

These increases were offset by $14 million in lower costs related to a 2005 restructuring at the distribution operations segment, primarily from a reduction in the workforce and elimination of unnecessary facilities. An additional $6 million decrease in operating expenses was related to the operation of assets, primarily in the energy investments segment, that were originally acquired in the 2004 acquisition of NUI and later sold in 2005.

Interest Expense Interest expense increased by $12 million, or 15%, from last year primarily as a result of higher working capital requirements due to increased inventory balances. Most of our utilities experienced a warmer winter in the 2005-2006 heating season than in the prior year. Consequently our utilities withdrew less volumes of natural gas inventory and Sequent carried higher inventory balances during the current period compared to 2005. Our average debt balances increased $222 million as shown in the following table.

	Nine months ended September 30,		
Dollars in millions	2006	2005	Change
Average debt outstanding (1)	$2,002	$1,780	$222
Average rate	6.1%	6.0%	0.1%

(1) Daily average of all outstanding debt.

If, for the nine months ended September 30, 2006, market interest rates on our variable rate debt (average rate of 5.4% for the nine month period) had been 100 basis points higher or lower, our year-to-date pretax interest expense would have changed by $6 million.

Income Taxes Income taxes increased by $22 million, or 28%, primarily as a result of higher pre-tax income for the nine months ended September 30, 2006. Our effective tax rate of 37.9% for the nine months ended September 30, 2006 was slightly lower than the 38.3% effective tax rate in the same period last year.

Distribution Operations

Distribution operations includes our natural gas local distribution utility companies, which construct, manage and maintain natural gas pipelines and distribution facilities and serve approximately 2.3 million end-use customers. Our distribution utilities include:

- Atlanta Gas Light
- Elizabethtown Gas
- Virginia Natural Gas
- Florida City Gas
- Chattanooga Gas
- Elkton Gas

Each utility operates subject to regulations of the state regulatory agencies in its service territories with respect to rates charged to our customers, maintenance of accounting records and various 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 should generally allow for the recovery of all prudently incurred costs, including a return on rate base sufficient to pay interest on debt and provide a reasonable return on common equity. Rate base generally consists of the original cost of utility plant in service, working capital, inventories and certain other assets; less accumulated depreciation on utility plant in service, net of deferred income tax liabilities and certain other deductions. We continuously monitor the performance of our utilities to determine whether rates need to be adjusted through the regulatory process.

Updates The following is a summary of significant developments with regard to our distribution operations segment that have occurred since we filed our Annual Report on Form 10-K for the year ended December 31, 2005, as amended.

Virginia Natural Gas On July 24, 2006, the Virginia State Corporation Commission (Virginia Commission) issued its order approving Virginia Natural Gas' performance-based rate (PBR) plan with modifications. These modifications, which were made by the Virginia Commission, include a requirement to construct and report on the progress of a pipeline connecting Virginia Natural Gas' northern and southern systems and reporting requirements to monitor compliance with the terms of the PBR plan. The estimated cost to construct the pipeline is $48-$60 million, and the pipeline is expected to be completed in 2009.

Virginia Natural Gas accepted the terms of the PBR plan as modified by the Virginia Commission in August 2006. The PBR plan, as modified, was effective August 1, 2006 with base rates frozen at current levels for five years.

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

Under the current structure, Chattanooga Gas' rates are designed to recover costs based on an assumed level of gas used by customers. If the customers use less gas, the rates do not allow Chattanooga Gas to fully recover the cost to serve the customer. The program we proposed would essentially decouple those conservation effects from cost-recovery through rates. In doing so, it would encourage consumers to conserve and Chattanooga Gas to support these energy conservation efforts, with no detrimental impact on Chattanooga Gas' operating results.

The TRA divided the case into two phases: one phase to examine the revenue requirements and traditional rate design issues and a second phase to review the CUA and ECP. Approximately $5 million of our request relates to the revenue requirement phase. On October 16, 2006, the Consumer Advocate and Protection Division of the Attorney General's Office of Tennessee filed a recommendation for a rate reduction for Chattanooga Gas of approximately $1 million. The primary differences in the two cases include return on equity and depreciation methodologies. The procedural schedule calls for hearings on the revenue requirement phase in early December, with rates to be effective around January 15, 2007. The second phase of the case is scheduled to begin February 9, 2007, and hearings are set for mid-August 2007. A final ruling is expected on or before September 30, 2007.

Elizabethtown Gas On August 18, 2006, the NJBPU issued an order adopting a pipeline replacement cost recovery rider program for the replacement of certain 8" cast iron main pipes and any unanticipated 10"-12" cast iron main pipes integral to the replacement of the 8" main pipes. The order allows Elizabethtown Gas to recognize revenues under a deferred recovery mechanism for costs to replace the pipe that exceeds a baseline amount of $3 million. The term of the stipulation is from the date of the order through December 31, 2008. Total replacement costs through December 31, 2008 are expected to be $10 million, of which $7 million will be eligible for the deferred recovery mechanism. Revenues recognized and deferred for recovery under the stipulation are estimated to be approximately $1 million. All costs incurred under the program will be included in Elizabethtown Gas' next rate case to be filed in 2009.

Results of Operations for our distribution operations segment for the three and nine months ended September 30, 2006 and 2005 are shown in the following tables.

Third quarter 2006 compared to third quarter 2005

	Three months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$253	$263	$(10)
Cost of gas	86	95	(9)
Operating margin	167	168	(1)
Operating expenses	117	120	(3)
Operating income	50	48	2
Other income	-	1	(1)
EBIT	$50	$49	$1

Operating Margin Operating margin decreased $1 million, or 1%, in the three months ended September 30, 2006 compared to the same period in 2005. The decrease was primarily the result of the loss of operating margin contributions in 2006 from the former appliance business discontinued in 2005 which was originally acquired with the acquisition of NUI Corporation. Chattanooga Gas also had slightly lower operating margins which were offset by Atlanta Gas Light's higher gas storage carrying charges and pipeline replacement revenues.

Operating Expenses Operating expenses decreased $3 million, or 3%, in 2006 compared to the same period in 2005, primarily due to lower costs resulting from our 2005 workforce and facilities restructuring.

Nine months 2006 compared to nine months 2005

In millions	Nine months ended September 30, 2006	2005	Change
Operating revenues	$1,186	$1,190	$(4)
Cost of gas	594	590	4
Operating margin	592	600	(8)
Operating expenses	361	378	(17)
Operating income	231	222	9
Other income	1	2	(1)
EBIT	$232	$224	$8
Metrics			
Average end-use customers (in thousands)	2,254	2,247	0.3%
Operation and maintenance expenses per customer	$111	$120	(8%)
EBIT per customer	$103	$100	3%
Customer usage (in millions of dekatherms)	227	249	(9%)
Heating degree days			% Warmer
Florida	493	531	7%
Georgia	1,499	1,595	6%
Maryland	2,726	3,270	17%
New Jersey	2,750	3,334	18%
Tennessee	1,699	1,781	5%
Virginia	1,877	2,329	19%

Operating Margin Operating margin decreased $8 million, or 1%, in the nine months ended September 30, 2006 compared to the same period in 2005. This decrease was primarily due to lower usage due to customer conservation and warmer weather. Operating margins decreased $3 million at Virginia Natural Gas, $2 million at Elizabethtown Gas, $2 million at Florida City Gas and $1 million at Chattanooga Gas. Also contributing to the decrease was a $3 million decrease from the discontinued appliance business operations.

These decreases were offset by a net increase in Atlanta Gas Light's operating margin of $3 million consisting of $4 million gas storage carrying costs, $1 million pipeline replacement program revenues. This was offset by $2 million due to the Georgia Public Service Commission's June 2005 Rate Order.

Operating Expenses Operating expenses decreased $17 million, or 4%, in 2006 compared to the same period in 2005, primarily due to lower compensation expense, lower facilities expense and a gain in 2006 on the sale of properties, partially offset by a slight increase in bad debt expense.

Compensation and facilities expense decreased $14 million in 2006 compared to the same period in 2005, primarily related to workforce and facilities restructuring in 2005. These decreases were offset by a $1 million increase in bad debt expense primarily at Elizabethtown Gas due to higher gas prices in 2006. Operating expenses also reflect a $2 million net gain compared to last year primarily due to the sale of properties in Georgia in 2006.

Retail Energy Operations

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

Although our ownership interest in the SouthStar partnership is 70%, the majority of SouthStar's earnings in Georgia are allocated by contract 75% to us and 25% to Piedmont. Earnings related to customers in Ohio and Florida will be allocated 70% to us and 30% to Piedmont. We record the earnings allocated to Piedmont as a minority interest in our condensed consolidated statements of income, and we record Piedmont's portion of SouthStar's capital as a minority interest in our condensed consolidated balance sheets.

Operating Margin SouthStar generates operating margin primarily in three ways. The first is through the sale of natural gas to retail customers in the residential, commercial and industrial sectors, primarily in Georgia where SouthStar captures a spread between wholesale and retail natural gas prices. The second way is through the collection of monthly service fees and customer late payment fees. The combination of these two retail price components are evaluated by SouthStar to ensure such pricing is structured to cover related retail customer costs, such as bad debt expense, and lost and unaccounted for gas, among others and to provide a reasonable profit. SouthStar's operating margins are impacted by seasonal weather, natural gas prices, customer growth, and SouthStar's related market share in Georgia, which has historically been approximately 35%. SouthStar employs strategies to attract and retain a higher credit-quality customer base. These strategies result not only in higher operating margin, as these customers tend to utilize higher volumes of natural gas, but also helps to mitigate bad debt expense due to the higher quality of customers.

The third way SouthStar generates margin is through the optimization of storage and transportation assets and effective commodity risk management. The efficient management of these assets and effective commodity risk management enable SouthStar to maintain competitive retail prices and operating margins. SouthStar is allocated storage and pipeline capacity that is utilized by SouthStar to provide gas supply to its customers in Georgia. Through hedging transactions, SouthStar manages exposures arising from changing commodity prices, utilizing natural gas storage transactions to capture margin from natural gas pricing differences that occur over time. SouthStar's risk management policies allow the use of derivative instruments for hedging and risk management purposes, but prohibit the use of derivative instruments for speculative purposes.

SouthStar accounts for inventories at the lower of weighted average cost or market. SouthStar evaluates the average cost of its natural gas inventories against market prices and determines whether any declines in market prices below the average cost are other than temporary. For declines considered to be other than temporary, SouthStar records adjustments against operating margin to reduce the weighted average cost of the natural gas inventory to market. SouthStar was not required to make an adjustment for the nine months ended September 30, 2006 or 2005; however, if prices for natural gas continue to decline, SouthStar could be required to make an adjustment in the three months ending December 31, 2006.

We have designated a portion of SouthStar's derivative transactions as cash flow hedges under Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133). We record derivative gains or losses arising from cash flow hedges in other comprehensive income (OCI) and reclassify them into earnings in the same period as the settlement of the underlying hedged item. We record any hedge ineffectiveness, defined as when the gains or losses on the hedging instrument do not offset and are greater than the losses or gains on the hedged item, in cost of gas in our consolidated statement of income in the period in which the ineffectiveness occurs. SouthStar currently has minimal hedge ineffectiveness. We have not designated the remainder of SouthStar's derivative instruments as hedges under SFAS 133 and, accordingly, we record changes in their fair value in earnings in the period of change.

SouthStar also enters into weather derivative instruments in order to preserve margins in the event of warmer than normal weather in the winter months. These contracts are accounted for using the intrinsic value method under Emerging Issues Task Force (EITF) 99-02, "Accounting for Weather Derivatives." The weather derivative contracts contain strike amount provisions based on cumulative heating degree days for the covered periods. In September 2006, SouthStar entered into weather derivatives (swaps and options) for the upcoming winter heating season. As of September 30, 2005, no weather derivative instruments were outstanding.

Updates The following is a summary of significant developments with regard to our retail energy operations segment that have occurred since we filed our Annual Report on Form 10-K for the year ended December 31, 2005, as amended.

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

Impact of Volatility in Natural Gas Prices SouthStar's operating margin and EBIT associated with the optimization of storage and transportation assets and commodity risk management during the three months ended September 30, 2006 were affected by the decline in natural gas prices. This is compared to the prior year when natural gas prices were significantly higher in part due to gas supply disruptions brought on by hurricanes Katrina and Rita. For those derivatives not designated as hedges under SFAS 133, SouthStar generally records mark-to-market losses as natural gas prices decrease and mark-to-market gains as natural gas prices increase.

SouthStar's operating margin and EBIT from the sale of natural gas to retail customers during the nine months ended September 30, 2006 have been affected by lower customer usage and higher bad debt expense as a result of higher natural gas prices in the 2005 - 2006 winter heating season. SouthStar's bad debt expense was $10 million for the nine months ended September 30, 2006, a $5 million increase from the same period last year. The increase in bad debt expense was largely driven by SouthStar's offering of payment arrangements to customers to help customers with higher natural gas bills during last year's winter heating season. SouthStar expects that these efforts will help mitigate the overall impact of bad debt expense as a percentage of operating revenues, which was 1.5% for the nine months ended September 30, 2006 compared to approximately 1.0% for the same period last year.

SouthStar also has experienced lower average usage per customer during the nine months ended September 30, 2006, compared to the same period last year due to a number of factors including warmer weather and the effects of customer conservation. Increased customer conservation is believed to be attributable to a number of factors including weather patterns, higher gas prices and the ongoing effects from replacement of natural gas appliances with more efficient units. In the first quarter of 2006, natural gas prices were higher and in the second quarter of 2006 weather was more than 50% warmer based on heating degree days compared to last year. Even though these two factors have contributed to a $12 decrease in operating margin relative to wholesale prices and normalized temperatures, SouthStar was able to manage its costs of gas through asset optimization (reflected as a reduction in costs of goods sold), which resulted in an overall increase in operating margin of $10 million for the nine months ended September 30, 2006 compared to last year.

Results of operations for our retail energy operations segment for the three and nine months ended September 30, 2006 and 2005 are shown in the following tables.

Third quarter 2006 compared to third quarter 2005

	Three months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$132	$153	$(21)
Cost of sales	119	129	(10)
Operating margin	13	24	(11)
Operating expenses	16	15	1
Operating income	(3)	9	(12)
Other income	1	-	1
Minority interest	-	(2)	2
EBIT	$(2)	$7	$(9)

Operating Margin Operating margin decreased $11 million, or 46%, largely driven by mark-to-market gains in 2005 compared to relatively flat hedging activity in 2006, resulting in a $6 million decrease. The 2005 mark-to-market gains were the result of hedges that were put in place to reduce exposure to higher natural gas prices. In 2006, these hedges experienced no gains as natural gas prices were generally falling during the period.

SouthStar's retail margins decreased by $5 million, due to slightly lower unit margins and higher interruptible margins in the third quarter of 2005. This was driven by peaking sales during curtailments and slightly lower average customer usage in 2006 compared to 2005. These decreases in retail margins were partially offset by higher retail price spreads in 2006 compared to 2005.

Operating Expenses Operating expenses were relatively flat compared to last year.

Minority Interest Minority interest decreased $2 million as a result of decreased operating income in the third quarter of 2006 compared to

2005.

Nine months 2006 compared to nine months 2005

	Nine months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$675	$627	$48
Cost of sales	551	513	38
Operating margin	124	114	10
Operating expenses	52	43	9
Operating income	72	71	1
Other expense	(1)	-	(1)
Minority interest	(19)	(18)	(1)
EBIT	$52	$53	$(1)
Metrics			
Average customers (in thousands)	535	534	0.2%
Market share in Georgia	35%	35%	-
Heating degree days	1,499	1,595	(6%)
Customer usage (in millions of dekatherms)	25.1	28.7	(13%)

Operating Margin Operating margin increased $10 million, or 9%, largely driven by improved storage margins of $18 million, offset by lower retail operating margins of $8 million. Storage margins were driven by improved optimization of storage and transportation assets and effective commodity risk management. Retail operating margins decreased primarily due to lower average usage due to weather that was 6% warmer than last year, customer conservation and lower late payment fees of $1 million due to an increase in the number of customers on payment arrangements, offset by favorable retail price spreads. Additionally, retail operating margins decreased compared to last year due to higher interruptible margins in the third quarter of 2005 driven by peaking sales during curtailments.

Operating Expenses Operating expenses increased $9 million, or 21%, primarily due to higher bad debt expense of $5 million, increased depreciation of $1 million due to the implementation of system enhancements, higher outside service costs of $1 million driven by the current year implementation of a new Energy Trading and Risk Management system and slightly higher incentive compensation costs of approximately $1 million as a result of continued improvement in SouthStar's operations.

Other Expense The retail energy operations segment made a $2 million charitable contribution in 2006.

Minority Interest Minority interest increased $1 million as a result of increased operating income in 2006 compared to 2005.

Wholesale Services

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

Sequent provides customers with natural gas from the major producing regions and market hubs primarily in the eastern and mid-continental United States. Sequent purchases transportation and storage capacity to meet its delivery requirements and customer obligations in the marketplace. Sequent's customers benefit from its logistics expertise and ability to deliver natural gas at prices that are advantageous relative to other alternatives available to its end-use customers. In 2006, Sequent entered into an agreement which should facilitate the expansion of its operations into the western United States and Canada. Sequent continues to work on projects and transactions to extend its operating territory and is entering into agreements with longer tenors, as well as evaluating opportunities to expand its business focus and models.

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

Updates The following is a summary of significant developments with regard to our wholesale services segment that have occurred since we filed our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005,

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

During the first quarter of 2006, Sequent entered into a contract for 35,000 million British thermal units (MMBtu's) per day of firm transportation capacity for a term of five years with an estimated commencement date in late 2007. The contract contained a five year extension option, which was exercised during the second quarter of 2006. This contract is subject to the counterparty receiving regulatory approval of their construction project. Once the contract commences, Sequent's cost for the capacity will be approximately $3 million per year.

As Sequent executes transactions to secure transportation capacity, it often enters into forward financial contracts to hedge its positions. The hedging instruments are derivatives, and Sequent reflects changes in the derivatives' fair value in its reported operating results. During the third quarter and first nine months of 2006, Sequent reported gains of $11 million associated with transportation capacity hedges. The majority of this amount will be reversed during the fourth quarter of 2006 and during 2007 as the positions are settled.

Sequent did not report any significant gains or losses on these types of hedges during 2005.

Energy Marketing and Risk Management Activities The tables below illustrate the change in the net fair value of Sequent's derivative instruments and energy-trading contracts during the three and nine months ended September 30, 2006 and 2005, and provide details of the net fair value of contracts outstanding as of September 30, 2006.

In millions	Three months ended September 30, 2006	2005
Net fair value of contracts outstanding at beginning of period	$54	$8
Contracts realized or otherwise settled during period	(28)	6
Change in net fair value of contracts	89	(122)
Net fair value of contracts outstanding at end of period	115	(108)
Less net fair value of contracts outstanding at beginning of period	54	8
Unrealized gain (loss) related to changes in the fair value of derivative instruments	$61	$(116)

In millions	Nine months ended September 30, 2006	2005
Net fair value of contracts outstanding at beginning of period	$(13)	$17
Contracts realized or otherwise settled during period	(7)	23
Change in net fair value of contracts	135	(148)
Net fair value of contracts outstanding at end of period	115	(108)
Less net fair value of contracts outstanding at beginning of period	(13)	17
Unrealized gain (loss) related to changes in the fair value of derivative instruments	$128	$(125)

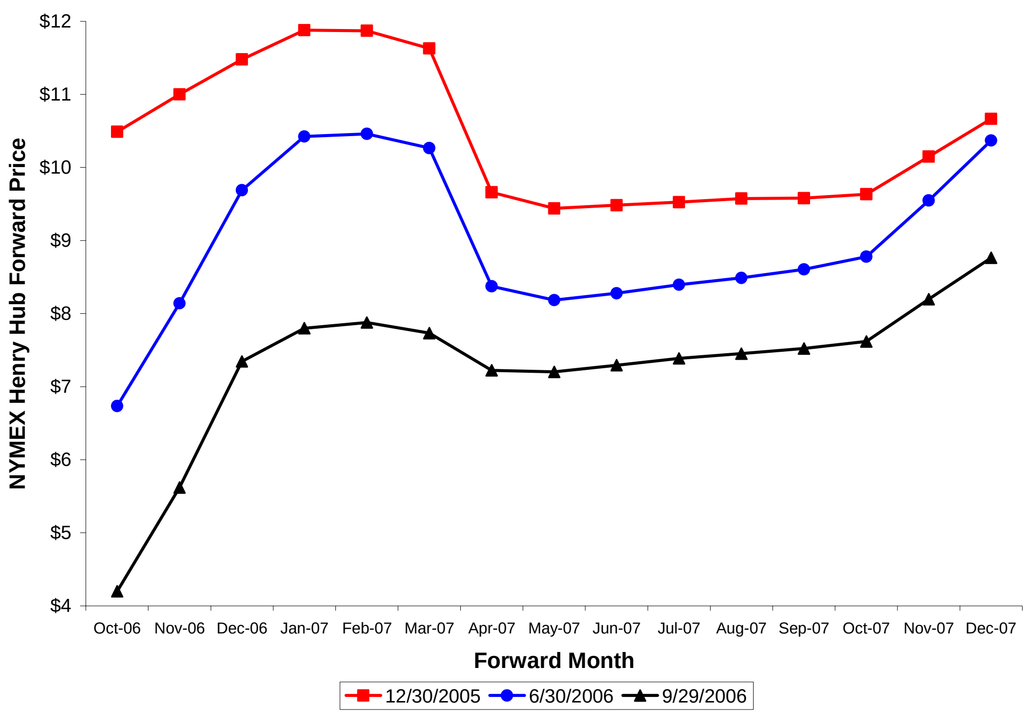
The sources of Sequent's net fair value at September 30, 2006 are as follows.

In millions	Prices actively quoted	Prices provided by other external sources
Maturity less than one year	$29	$72
Maturity 1-2 years	3	9
Maturity greater than three years	-	2
Total net fair value	$32	$83

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 transactions that represent the cost to transport the commodity from a NYMEX delivery point to the contract delivery point. Sequent’s basis spreads are primarily based on quotes obtained either directly from brokers or through electronic trading platforms.

At September 30, 2006, Sequent’s commodity-related derivative financial instruments represented purchases (long) of 615 Bcf and sales (short) of 651 Bcf, with approximately 94% and 95% scheduled to mature in less than two years and the remaining 6% and 5% in three to nine years, respectively. At September 30, 2006, the fair value of these derivatives was reflected in our condensed consolidated balance sheet as an asset of $143 million and a liability of $28 million.

Storage Inventory Outlook The following graph presents the NYMEX forward natural gas prices as of December 31, 2005, June 30, 2006 and September 30, 2006 for the period of October 2006 through December 2007, and reflects the prices at which Sequent could buy natural gas at the Henry Hub for delivery in the same time period. The Henry Hub, located in Louisiana, is the largest centralized point for natural gas spot and futures trading in the United States. NYMEX uses the Henry Hub as the point of delivery for its natural gas futures contracts. Many natural gas marketers also use the Henry Hub as their physical contract delivery point or their price benchmark for spot trades of natural gas.



Sequent's expected withdrawals from physical salt dome and reservoir storage are presented in the table below along with the expected gross margin. Sequent's expected gross margin is net of the impact of regulatory sharing and reflects the amounts that it would expect to realize in future periods based on the inventory withdrawal schedule and forward natural gas prices at September 30, 2006. Sequent's storage inventory is fully hedged with futures as the NYMEX short positions are equal to the physical long positions, which results in an overall locked-in margin, timing notwithstanding. Sequent's physical salt dome and reservoir volumes are presented in NYMEX equivalent contract units of 10,000 MMBtu's.

	Q4 2006	Q1 2007	Total
Salt dome	334	67	401
Reservoir	519	617	1,136
Total volumes	853	684	1,537
Expected gross margin *(in millions)*	$8	$14	$22

As of September 30, 2006, the weighted average cost of natural gas in inventory was $6.27 for physical salt dome storage and $4.99 for physical reservoir storage. These costs reflect adjustments that were recorded at the end of each quarter in 2006 in order to reduce the value of Sequent's natural gas inventory to market value at certain locations. Sequent reduced the inventory value by $5 million at March 31, $8 million at June 30 and $20 million at September 30, after regulatory sharing, or $33 million for the nine months ended September 30, 2006. These adjustments negatively impacted Sequent's reported earnings. However, as the carrying value of the inventory was reduced, the expected gross margin in the table above increased by an equal and offsetting amount. Sequent anticipates the majority of the aggregate $33 million of adjustments to be recovered by year-end, with the remainder to be recovered during the first quarter of 2007 as both the inventory is withdrawn from storage and sold and the hedging instrument in place to lock in the original margin on the storage transaction is settled.

Sequent's inventory level and pricing as of September 30, 2006 should result in a gross margin of approximately $8 million in 2006 and $14 million in 2007 if all factors remain the same. This could change significantly if Sequent adjusts its daily injection and withdrawal plans in response to changes in market conditions in future months. Based upon Sequent's expected year-end storage positions at September 30, 2006, a $1.00 change in the forward NYMEX prices would result in a $6 million impact to Sequent's reported EBIT after regulatory sharing.

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

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

Sequent enters into forward NYMEX contracts to hedge its park and loan transactions. While the hedging instruments mitigate the price risk associated with the delivery and receipt of natural gas, they can also result in volatility in Sequent's reported results during the period before the initial delivery or receipt of natural gas. During this period if the forward NYMEX prices of the delivery and receipt months do not change in equal amounts, Sequent will report a net unrealized gain or loss on the hedges.

During the first six months of 2006, Sequent reported unrealized losses of $4 million associated with its park and loan hedging instruments. The majority of these losses were recovered during the third quarter as the initial delivery of natural gas occurred. Sequent did not report any significant gains or losses on park and loan hedges during the third quarter of 2006 or during all of 2005.

Results of Operations for the wholesale services segment for the three and nine months ended September 30, 2006 and 2005 are as follows:

Third quarter 2006 compared to third quarter 2005

In millions	Three months ended September 30, 2006	2005	Change
Operating revenues	$74	$1	$73
Cost of sales	20	-	20
Operating margin	54	1	53
Operating expenses	14	7	7
Operating income	40	(6)	46
Other income	-	-	-
EBIT	$40	$(6)	$46
Metrics			
Physical sales volumes (Bcf/day)	2.33	2.33	-%

Operating Margin The following table indicates the significant changes in operating margin:

In millions	
Operating margin for third quarter 2005	$1
Net change in the fair value of storage hedges	84
Net change in the fair value of transportation hedges	11
Lower of cost or market adjustment	(20)
Wholesale services commercial activities	(22)
Operating margin for third quarter 2006	$54

The $53 million increase in operating margin was primarily a result of the recognition of hedge gains related to Sequent's storage and transportation positions compared to hedge losses reported in the prior period. The period over period increase associated with hedge values was partially offset by the impact of a lower-of-cost-or-market (LOCOM) adjustment that was recorded in 2006 and the additional third quarter earnings in 2005 associated with increased market volatility caused by hurricane activity in the Gulf of Mexico.

During the third quarter of 2006, forward NYMEX prices declined significantly, which resulted in the recognition of gains of $38 million associated with the financial instruments used to hedge Sequent's inventory positions. In contrast, during the third quarter of 2005, forward NYMEX prices increased significantly, which resulted in the recognition of losses of $46 million associated with Sequent's inventory hedges. In addition Sequent recognized $11 million in gains associated with the financial instruments used to hedge its transportation capacity.

Also, due to the decline in natural gas prices in the third quarter of 2006, Sequent evaluated the weighted average cost of its natural gas inventory. As a result, Sequent recorded a LOCOM adjustment of $20 million after regulatory sharing, which is presented as "Cost of sales." Sequent was not required to make a similar adjustment during 2005.

Although Sequent experienced relatively strong quarterly performance during 2006 due to hot weather and advantageous storage opportunities, the prior year quarter produced greater margins due to the unusually high levels of natural gas market volatility resulting from hurricane activity in the Gulf of Mexico.

Operating Expenses Sequent's operating expenses increased $7 million, or 100%, primarily due to increased incentive compensation resulting from the increased margin. The increased expenses were partially offset by lower corporate overhead costs.

Nine months 2006 compared to nine months 2005

In millions	Nine months ended September 30, 2006	2005	Change
Operating revenues	$141	$21	$120
Cost of sales	33	-	33
Operating margin	108	21	87
Operating expenses	35	21	14
Operating income	73	-	73
Other income	-	-	-
EBIT	$73	$-	$73
Metrics			
Physical sales volumes (Bcf/day)	2.18	2.27	(4%)

Operating Margin The following table indicates the significant changes in operating margin:

In millions	
Operating margin for nine months 2005	$21
Wholesale services commercial activities	11
Net change in the fair value of storage hedges	98
Net change in the fair value of transportation hedges	11
Lower of cost or market adjustments	(33)
Operating margin for nine months 2006	$108

The $87 million increase in operating margin was partially a result of improved commercial opportunities associated with larger seasonal storage spreads during the first half of 2006 and above average temperatures during the late summer months. These conditions helped to offset the mild weather during the previous winter and early summer and the lower level of hurricane activity experienced in the Gulf of Mexico this year.

Additionally, during the first nine months of the year the reported results were positively impacted by forward NYMEX prices moving downward and the narrowing of future seasonal spreads which resulted in the recognition of $49 million of gains on Sequent's economic storage hedges in contrast to the prior period when forward prices increased and resulted in the recognition of $49 million of hedge losses. During 2006, Sequent also recognized $11 million in gains associated with the financial instruments used to hedge its transportation capacity. There were no significant gains or losses associated with transportation hedges recognized in the prior year nine-month period.

The positive impact from the price movements in 2006 was partially offset by $33 million of LOCOM adjustments that Sequent recorded at certain storage locations to reduce the carrying value of its natural gas inventory to current market prices. No LOCOM adjustments were required in the prior year nine-month period.

Operating Expenses Sequent's operating expenses increased $14 million, or 67%, primarily due to higher costs associated with an increase in the number of employees to support Sequent's growth and additional incentive compensation costs directly related to stronger financial performance in the first nine months of 2006, as well as a higher percentage of corporate overhead costs, primarily due to Sequent's improved earnings. The increased expenses were partially offset by lower costs associated with outside services.

Energy Investments

Our energy investments segment includes:

- Pivotal Jefferson Island Storage & Hub, LLC (Pivotal Jefferson Island)
- Pivotal Propane of Virginia, Inc. (Pivotal Propane)
- AGL Networks, LLC (AGL Networks)

Pivotal Jefferson Island generates operating margin primarily through customer contracts for the purchase of capacity in its salt dome caverns. Pivotal Jefferson Island's capacity in its currently operational caverns is fully subscribed, with the terms of subscription contracts expiring at staggered dates from 2007 to 2012. Pivotal Jefferson Island also generates operating margin from interruptible customers when market conditions and the amount of available physical space in the caverns are conducive for customers to store gas in the caverns.

Sale of assets Until their sale in August 2005, our energy investment segment included our 50% interest in Saltville Gas Storage Company, LLC (Saltville) and associated subsidiaries and our wholly-owned subsidiaries, Virginia Gas Pipeline and Virginia Gas Storage. These companies, which we acquired in our purchase of NUI in 2004, were sold for $66 million to a subsidiary of Duke Energy Corporation, the other 50% partner in the Saltville joint venture.

Updates The following is a summary of significant developments with regard to our energy investments segment that have occurred since we filed our Annual Report on Form 10-K for the year ended December 31, 2005.

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

Pivotal Jefferson Island began the approximate $160 million expansion project earlier this year to add a third and fourth storage cavern at the facility. Pivotal Jefferson Island expected to complete the third cavern in 2009 and expected the fourth cavern to be operational in 2011. As of September 30, 2006, Pivotal Jefferson Island had incurred $17 million of expenditures in the expansion project.

In September 2006, Pivotal Jefferson Island filed suit against the State of Louisiana to maintain its lease at Lake Peigneur to complete its expansion project. Pivotal Jefferson Island stopped most of the construction activities on the third cavern. At this time we are unable to predict the delays this litigation will have on Pivotal Jefferson Island's anticipated completion of the expansion project or the outcome of the litigation.

For additional information regarding the Pivotal Jefferson Island litigation, see "Note 8 - Commitments and Contingencies" in "Notes to Condensed Consolidated Financial Statements (Unaudited)" in Item 1 of Part I of this report.

Results of operations for our energy investments segment for the three and nine months ended September 30, 2006 and 2005 are as follows.

Third quarter 2006 compared to third quarter 2005

	Three months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$10	$14	$(4)
Cost of sales	-	4	(4)
Operating margin	10	10	-
Operating expenses	7	5	2
Operating income	3	5	(2)
Other income	-	-	-
EBIT	$3	$5	$(2)

Operating Margin There was no change in the operating margin compared to last year, largely due to the loss of $1 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but later sold in 2005, offset by a $1 million increase in operating margin at AGL Networks due to increased customer base. Pivotal Jefferson Island and Pivotal Propane's operating margins were flat compared to the prior year.

Operating Expenses Operating expenses increased $2 million, or 40%, compared to last year primarily due to project development expenses of $2 million.

Nine months 2006 compared to nine months 2005

	Nine months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$30	$43	$(13)
Cost of sales	4	12	(8)
Operating margin	26	31	(5)
Operating expenses	19	17	2
Operating income	7	14	(7)
Other income	-	1	(1)
EBIT	$7	$15	$(8)

Operating Margin Operating margin decreased $5 million, or 16%, largely due to the loss of $8 million of operating margin contributions from certain assets we acquired with the 2004 acquisition of NUI but later sold in 2005. Pivotal Jefferson Island's operating margin increased slightly compared to the prior year in part due to increased interruptible margin opportunities. AGL Networks' operating margin increased by $1 million due to an increased customer base, and Pivotal Propane contributed a $2 million increase primarily in the first quarter of 2006 as it did not become operational until April 2005.

Operating Expenses Operating expenses increased $2 million, or 12%, compared to last year. Operating expenses at Pivotal Propane increased as it did not become operational until April 2005. Pivotal Jefferson Island's operating expenses increased by $1 million due to compressor related costs. AGL Networks operating expenses increased by $1 million due to restructuring expenses. Additionally, project and corporate development costs increased $6 million. These costs were offset by decreased operating expenses of $6 million resulting from the 2005 sale of certain assets that we originally acquired with the 2004 acquisition of NUI.

Corporate

Our corporate segment consists of our nonoperating business units, including AGL Services Company (AGSC) and AGL Capital Corporation (AGL Capital). Our corporate segment also includes intercompany eliminations for transactions between our operating business segments.

We allocate substantially all of AGSC's operating expenses to our operating segments in accordance with state regulations. Our operating segments' EBIT includes the impact of these allocations.

Results of operations for our corporate segment for the three and nine months ended September 30, 2006 and 2005 are listed in the tables below. As a nonoperating segment, Corporate's comparative EBIT variances for the indicated periods primarily reflect the relative change in various general and administrative expenses, such as payroll, benefits and incentives, insurance, fleet services and outside services.

Third quarter 2006 compared to third quarter 2005

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	Three months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$(35)	$(38)	$3
Cost of sales	(35)	(37)	2
Operating margin (1)	-	(1)	1
Operating expenses (2)	-	1	(1)
Operating loss	-	(2)	2
Other expenses	(1)	(1)	-
EBIT	$(1)	$(3)	$2

(1) Includes intercompany eliminations
(2) The following table summarizes the major components of operating expenses.

	Three months ended September 30,		
In millions	2006	2005	Change
Payroll	$14	$15	$(1)
Benefits and incentives	7	6	1
Outside services	10	12	(2)
All other expenses	9	11	(2)
Allocations	(40)	(43)	3
Total operating expenses	$-	$1	$(1)

Nine months 2006 compared to nine months 2005

	Nine months ended September 30,		
In millions	2006	2005	Change
Operating revenues	$(118)	$(145)	$27
Cost of sales	(118)	(143)	25
Operating margin (1)	-	(2)	2
Operating expenses (2)	5	4	1
Operating loss	(5)	(6)	1
Other expenses	(2)	(1)	(1)
EBIT	$(7)	$(7)	$-

(1) Includes intercompany eliminations
(2) The following table summaries the major components of operating expenses.

	Nine months ended September 30,		
In millions	2006	2005	Change
Payroll	$41	$43	$(2)
Benefits and incentives	21	20	1
Outside services	31	31	-
All other expenses	34	42	(8)
Allocations	(122)	(132)	10
Total operating expenses	$5	$4	$1

Liquidity and Capital Resources

To meet our capital and liquidity requirements, we rely on operating cash flow; short-term borrowings under our commercial paper program, which is backed by our supporting credit agreement (Credit Facility); borrowings under Sequent's, Pivotal Utility's and SouthStar's lines of credit; and borrowings or stock issuances in the long-term capital markets. Our issuance of various securities, including long-term and short-term debt, is subject to customary approval or authorization by state and federal regulatory bodies, including state public service commissions and the SEC. Furthermore, a substantial portion of our consolidated assets, earnings and cash flow is derived from the operation of our regulated utility subsidiaries, whose legal authority to pay dividends or make other distributions to us is subject to regulation. We believe these sources will be sufficient for our working capital needs, debt service obligations and scheduled capital expenditures for the foreseeable future.

We will continue to evaluate the need to increase our available liquidity based on our view of working capital requirements, including the impact of changes in natural gas prices, liquidity requirements established by the rating agencies and other factors. Additionally, our liquidity and capital resource requirements may change in the future due to a number of other factors, some of which we cannot control. These factors include:

- the seasonal nature of the natural gas business and our resulting short-term borrowing requirements, which typically peak during colder months
- increased gas supplies required to meet our customers' needs during cold weather
- changes in wholesale prices and customer demand for our products and services
- regulatory changes and changes in ratemaking policies of regulatory commissions
- contractual cash obligations and other commercial commitments
- interest rate changes
- pension and postretirement funding requirements
- changes in income tax laws
- margin requirements resulting from significant increases or decreases in our commodity prices
- operational risks
- the impact of natural disasters, including weather

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

We calculate any required pension contributions using the projected unit credit cost method. We are not required to make any contribution to our pension plans in 2006, but we made a voluntary contribution of $5 million to the AGL Resources Inc. Retirement Plan in October 2006. The following table illustrates our expected future contractual obligations as of September 30, 2006.

		Payments due before December 31,			
In millions	Total	2006	2007 & 2008	2009 & 2010	2011 & thereafter
Pipeline charges, storage capacity and gas supply (1) (2)	$1,774	$86	$634	$501	$553
Long-term debt	1,634	-	2	2	1,630
Interest charges on outstanding debt (3)	1,418	22	198	198	1,000
Short-term debt	441	441	-	-	-
PRP costs (4)	246	6	77	91	72
Operating leases (5)	149	8	48	34	59
Environmental remediation costs (4)	101	4	21	68	8
Total	$5,763	$567	$980	$894	$3,322

(1) Charges recoverable through a PGA mechanism or alternatively billed to Marketers. Also includes demand charges associated with Sequent.
(2) A subsidiary of NUI entered into two 20-year agreements for the firm transportation and storage of natural gas during 2003 with annual aggregate demand charges of approximately $5 million. As a result of our acquisition of NUI and in accordance with SFAS No. 141, "Business Combinations," we valued the contracts at fair value and established a long-term liability that will be amortized over the remaining lives of the contracts.
(3) Floating rate debt is based on the interest rate as of September 30, 2006 and the maturity of the underlying debt instrument.
(4) Includes charges recoverable through rate rider mechanisms.
(5) We have certain operating leases with provisions for step rent or escalation payments and certain lease concessions. We account for these leases by recognizing the future minimum lease payments on a straight-line basis over the respective minimum lease terms, in accordance with SFAS No. 13, "Accounting for Leases." However, this accounting treatment does not affect the future annual operating lease cash obligations as shown herein.

We also have incurred various financial commitments in the normal course of business. Contingent financial commitments represent obligations that become payable only if certain predefined events occur, such as financial guarantees, and include the nature of the guarantee and the maximum potential amount of future payments that could be required of us as the guarantor. The following table illustrates our expected contingent financial commitments as of September 30, 2006.

		Commitments due before Dec. 31,	
In millions	Total	2006	2007 & thereafter
Standby letters of credit and performance and surety bonds	$23	$11	$12

Cash flow provided from operating activities For the first nine months of 2006, our net cash flow provided from operating activities was $341 million, an increase of $153 million, or 81%, from the same period last year.

The increase was primarily a result of higher earnings in 2006 of $38 million, recovering working capital during 2006 that was deployed during 2005 due to the significantly higher commodity prices and the amount for working capital deployed during the last quarter of 2004 when prices were significantly lower. Contributing to the increase was a decrease in the amount of natural gas purchased for inventory at Sequent and our utilities of $103 million as a result of mild weather in the prior heating season and therefore higher inventory balances for the upcoming heating season.

Cash flow used in investing activities Cash used in investing activities consists primarily of property, plant and equipment expenditures. We made investments of $190 million in property, plant and equipment during the nine months ended September 30, 2006 and $194 million in the same period in 2005.

The 2005 expenditures included the $32 million asset acquisition of a 250-mile pipeline in Georgia from Southern Natural Gas in 2005. The 2006 expenditures included $12 million at our corporate segment on information technology projects and $15 million at Pivotal Jefferson Island for the commencement of its cavern expansion project in 2006. In 2006, we received approximately $5 million for the sale of land associated with former operating sites.

Cash flow used in financing activities Our financing activities primarily consist of borrowings and payments of short-term debt, distributions to minority interests, cash dividends on our common stock, issuances of common stock and purchases and issuances of treasury shares. Our capitalization and financing strategy is intended to ensure that we are properly capitalized with the appropriate mix of equity and debt securities. This strategy includes our active management of the percentage of our total debt relative to our total capitalization, as well as the term and interest rate profile of our debt securities.

We also work to maintain or improve our credit ratings on our senior notes to effectively manage our existing financing costs and enhance our ability to raise additional capital on favorable terms. Factors we consider important in assessing our credit ratings include our balance sheet leverage, capital spending, earnings, cash flow generation, available liquidity and overall business risks. We do not have any trigger events in our debt instruments that are tied to changes in our credit ratings or our stock price and have not entered into any transaction that would require us to issue equity based on credit ratings or other trigger events. As of September 30, 2006, our senior unsecured debt ratings were BBB+ from Standard & Poor's Ratings Services (S&P), Baa1 from Moody's Investors Service (Moody's) and A- from Fitch Ratings (Fitch).

Our debt instruments and other financial obligations include provisions that, if not complied with, could require early payment, additional collateral support or similar actions. Our most important default events include maintaining covenants with respect to maximum leverage ratio, insolvency events, nonpayment of scheduled principal or interest payments, and acceleration of other financial obligations and change of control provisions. Our credit facility's financial covenants require us to maintain a ratio of total debt to total capitalization of no greater than 70%; however, our goal is to maintain debt levels between 50% and 60% of total capitalization. We are currently in compliance with all existing debt provisions and covenants.

We believe that accomplishing these capitalization objectives and maintaining sufficient cash flow are necessary to maintain our investment-grade credit ratings and to allow us access to capital at reasonable costs. The components of our capital structure, as of the dates indicated, are summarized in the following table:

$ in millions	September 30, 2006		December 31, 2005		September 30, 2005	
Short-term debt	$440	12%	$521	14%	$343	10%
Current portion of long-term debt	1	-	1	-	1	-
Long-term debt (1)	1,634	45	1,615	45	1,616	47
Total debt	2,075	57	2,137	59	1,960	57
Common shareholders' equity	1,581	43	1,499	41	1,451	43
Total capitalization	$3,656	100%	$3,636	100%	$3,411	100%

(1) Net of interest rate swaps

In May 2006, we used the proceeds from the sale of commercial paper to redeem $150 million principal amount of junior subordinated debentures and to pay a $5 million note representing our investment in the related Trust. We refinanced the commercial paper borrowings with long-term debt on June 30, 2006.

In August 2006, we completed a new credit facility that supports our commercial paper program. Under the terms of the credit facility, the aggregate principal amount available has been increased from $850 million to $1 billion and we have the option to increase the aggregate principal amount available for borrowing to $1.25 billion on not more than three occasions during each calendar year. The credit facility expires August 31, 2011. The availability of borrowings under our credit facility is limited and subject to a total-debt-to-capital ratio financial covenant specified within the credit facility, which we currently meet.

In 2006, we extended Sequent's two lines of credit through June 2007 and August 2007. In addition, we extended Pivotal Utility Holdings, Inc. line of credit through August 2007. These unsecured lines of credit are unconditionally guaranteed by us. For more information, see "Note 7 – Debt" in "Notes to Condensed Consolidated Financial Statements (Unaudited)" in Item 1 of Part I of this report.

Critical Accounting Policies and Estimates

The preparation of our financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. We evaluate our estimates on an ongoing basis, and our actual results may differ from these estimates. Our critical accounting policies used in the preparation of our consolidated financial statements are described in our Annual Report on Form 10-K, as amended, for the year ended December 31, 2005 and include the following:

- Pipeline Replacement Program
- Environmental Remediation Liabilities
- Derivatives and Hedging Activities
- Accounting for Contingencies
- Accounting for Pension and Other Postretirement Benefits

Each of our critical accounting policies and estimates involves complex situations requiring a high degree of judgment either in the application and interpretation of existing literature or in the development of estimates that impact our financial statements. There have been no significant changes to our critical accounting policies from those disclosed in our Annual Report on Form 10-K as amended, for the year ended December 31, 2005.

Accounting Developments

For information regarding accounting developments, see "Note 1 – Accounting Policies and Methods of Application," and "Note 5 - Stock-based Compensation Plans" in "Notes to Condensed Consolidated Financial Statements (Unaudited)" in Item 1 of Part I of this report.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to risks associated with commodity prices, interest rates and credit. Commodity price risk is defined as the potential loss that we may incur as a result of changes in the fair value of a particular instrument or commodity. Interest rate risk results from our portfolio of debt and equity instruments that we issue to provide financing and liquidity for our business. Credit risk results from the extension of credit throughout all aspects of our business but is particularly concentrated at Atlanta Gas Light in distribution operations and in wholesale services. Our risk management activities and related accounting treatments are described in further detail in “Note 2, - Risk Management” in “Notes to Condensed Consolidated Financial Statements (Unaudited)” in Item 1 of Part I of this report.

Commodity Price Risk

We employ a systematic approach to evaluating and managing the risks associated with our contracts related to wholesale marketing and risk management, including Value at Risk (VaR). A 95% confidence interval is used to evaluate our exposures. A 95% confidence interval means there is a 5% probability that the actual change in portfolio value will be greater than the calculated VaR value over the holding period. We currently use a 1-day holding period to evaluate our VaR exposure, and we calculate VaR based on the variance-covariance technique. Additionally, our calculation requires us to make a number of assumptions, regarding matters such as prices, volatilities, and positions. 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 are no established industry standards for calculating VaR or for the assumptions underlying such calculations.

Retail Energy Operations SouthStar’s use of derivatives is governed by a risk management policy, created and monitored by its risk management committee, which prohibits the use of derivatives for speculative purposes. A 95% confidence interval is used to evaluate its VaR. The following table provides the quarterly average on SouthStar’s 1-day holding period VaR for the three and nine months ended September 30, 2006 and 2005.

Three months ended September 30

In millions	1-day
Avg. 2006	$0.1
Avg. 2005	$0.1

Nine months ended September 30

In millions	1-day
Avg. 2006	$0.1
Avg. 2005	$0.1

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

Wholesale Services This segment routinely utilizes various types of financial and other instruments to mitigate certain commodity price risks inherent in the natural gas industry. These instruments include a variety of exchange-traded and over-the-counter energy contracts, such as forward contracts, futures contracts, options contracts and financial swap agreements. The following tables include the average values of Sequent’s energy marketing and risk management assets and liabilities as of September 30, 2006 and 2005 and the fair values as of September 30, 2006, December 31, 2005 and September 30, 2005. Sequent bases the average values on monthly averages for the nine months ended September 30, 2006 and 2005.

	Average values at September 30,	
In millions	2006	2005
Asset	$88	$71
Liability	49	83

	Fair Values at		
In millions	Sept. 30, 2006	Dec. 31, 2005	Sept. 30, 2005
Asset	$143	$97	$150
Liability	28	110	258

Sequent’s open exposure is managed in accordance with established policies that limit market risk and require daily reporting of potential financial exposure to senior management, including the chief risk officer. Because Sequent generally manages physical gas assets and economically protects its positions by hedging in the futures markets, Sequent's open exposure is generally immaterial, permitting Sequent to operate within relatively low VaR limits. Sequent employs daily risk testing, using both VaR and stress testing, to evaluate the risks of its open positions.

Sequent's management actively monitors open commodity positions and the resulting VaR. Sequent continues to maintain a relatively matched book, where the total buy volume is close to sell volume. Based on a 95% confidence interval and employing a 1-day holding period for all positions, Sequent's portfolio of positions for the three and nine months ended September 30, 2006 and 2005 had the following VaRs.

In millions	Three months ended September 30, 2006	Three months ended September 30, 2005	Nine months ended September 30, 2006	Nine months ended September 30, 2005
Period end	$1.6	$0.8	$1.6	$0.8
Average	1.3	0.7	1.2	0.3
High	2.5	1.1	2.5	1.1
Low	0.7	0.5	0.7	0.0

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

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

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

Interest Rate Risk

Interest rate fluctuations expose our variable-rate debt to changes in interest expense and cash flows. Our policy is to manage interest expense using a combination of fixed-rate and variable-rate debt. To facilitate the achievement of desired fixed-rate to variable-rate debt ratios, AGL Capital entered into interest rate swaps whereby it agreed to exchange, at specified intervals, the difference between fixed and variable amounts calculated by reference to agreed-on notional principal amounts. These swaps are designated to hedge the fair values of $100 million of the $300 million principal amount of senior notes due in 2011.

In the third quarter of 2005 and the second quarter of 2006, in anticipation of our $175 million senior notes offering in June 2006, we entered into treasury lock derivative agreements to hedge our exposure to increases in interest rates. We received an $11 million settlement payment from our counterparties, which we will amortize over the next 10 years through interest expense. These derivatives reduced the annual interest rate on our 6.375% senior notes by approximately 60 basis points.

Credit 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 Sequent is engaged in more than one outstanding derivative transaction with the same counterparty and it also has a legally enforceable netting agreement with that counterparty, the "net" mark-to-market exposure represents the netting of the positive and negative exposures with that counterparty and a reasonable measure of Sequent's credit risk. Sequent also uses other netting agreements with certain counterparties with whom it conducts significant transactions.

Master netting agreements enable Sequent to net certain assets and liabilities by counterparty. Sequent also nets across product lines and against cash collateral, provided the master netting and cash collateral agreements include such provisions. Additionally, Sequent may require counterparties to pledge additional collateral when deemed necessary. Sequent conducts credit evaluations and obtains appropriate internal approvals for its counterparty's line of credit before executing any transaction with the counterparty. In most cases, the counterparty must have a minimum long-term debt rating of Baa3 from Moody's and BBB- from S&P. Generally, Sequent requires credit enhancements by way of guaranty, cash deposit or letter of credit for transactions with 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 September 30, 2006, Sequent's top 20 counterparties represented approximately 61% of the total counterparty exposure of $280 million, derived by adding together the top 20 counterparties' exposures and dividing by the total of Sequent's counterparties' exposures.

As of September 30, 2006, Sequent's counterparties, or the counterparties' guarantors, had a weighted average S&P equivalent credit rating of A-, which is consistent with the prior year. The S&P equivalent credit rating is determined by a process of converting the lower of the S&P or Moody's ratings to an internal rating ranging from nine to one, with nine being equivalent to AAA/Aaa by S&P and Moody's and one being D or Default by S&P and Moody's. A counterparty that does not have an external rating is assigned an internal rating based on the strength of the financial ratios of that counterparty.

To arrive at the weighted average credit rating, each counterparty's assigned internal rating is multiplied by the counterparty's credit exposure and summed for all counterparties. That sum is divided by the aggregate total counterparties' exposures, and this numeric value is then converted to an S&P equivalent. The following table shows Sequent's commodity receivable and payable positions as of September 30, 2006, December 31, 2005 and September 30, 2005.

In millions	Sept. 30, 2006	Dec. 31, 2005	Sept. 30, 2005
Gross receivables			
Receivables with netting agreements in place:			
Counterparty is investment grade	$264	$462	$488
Counterparty is non-investment grade	17	66	69
Counterparty has no external rating	51	113	92
Receivables without netting agreements in place:			
Counterparty is investment grade	11	34	20
Counterparty is non-investment grade	-	-	1
Counterparty has no external rating	1	-	-
Total gross receivables	$344	$675	$670
Gross payables			
Payables with netting agreements in place:			
Counterparty is investment grade	$197	$456	$388
Counterparty is non-investment grade	45	56	57
Counterparty has no external rating	119	255	188
Payables without netting agreements in place:			
Counterparty is investment grade	12	4	14
Counterparty has no external rating	-	4	3
Total gross payables	$373	$775	$650

Sequent has certain trade and credit contracts that have explicit rating trigger events in case of a credit rating downgrade. These rating triggers typically give counterparties the right to suspend or terminate credit if our credit ratings are downgraded to non-investment grade status. Under such circumstances, Sequent would need to post collateral to continue transacting business with some of its counterparties. Posting collateral would have a negative effect on our liquidity. If such collateral were not posted, Sequent's ability to continue transacting business with these counterparties would be impaired. If at September 30, 2006 our credit ratings had been downgraded to non-investment grade status, the required amounts to satisfy potential collateral demands under such agreements between Sequent and its counterparties would have totaled $13 million.

Item 4. Controls and Procedures

(a) ***Evaluation of disclosure controls and procedures*.** Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined in Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the Exchange Act), as of September 30, 2006, the end of the period covered by this report. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2006 in providing a reasonable level of assurance that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods in SEC rules and forms, including a reasonable level of assurance that information required to be disclosed by us in such reports is accumulated and communicated to our management, including our principal executive officer and our principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

(b) ***Changes in internal controls over financial reporting*.** There were no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II -- OTHER INFORMATION

Item 1. Legal Proceedings

The nature of our business ordinarily results in periodic regulatory proceedings before various state and federal authorities and litigation incidental to the business. For information regarding pending federal and state regulatory matters, see “Note 8 – Commitments and Contingencies” contained in Item 1 of Part I under the caption “Notes to Condensed Consolidated Financial Statements (Unaudited),” and "Results of Operations – Distribution Operations" contained in Item 2 of Part I under the caption "Management's Discussion and Analysis of Financial Condition and Results of Operations." With regard to other legal proceedings, we are a party, as both plaintiff and defendant, to a number of other suits, claims and counterclaims on an ongoing basis. Management believes that the outcome of all such other litigation in which it is involved will not have a material adverse effect on our consolidated financial statements.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

The following table presents information about our purchases of our common stock during the third quarter of 2006:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
July 2006	95,770 (1) (2)	$37.88	95,500	7,487,250
August 2006	113,872 (1) (2)	36.75	113,500	7,373,750
September 2006	106,358 (1) (2)	35.88	104,250	7,269,500
Total third quarter	**316,000**	**$36.80**	**313,250**	**7,269,500**

(1) In February 2006, we announced that our Board of Directors authorized a plan to repurchase up to 8 million shares of our outstanding common stock over a five-year period.

(2) Pursuant to our stock-based compensation plans, participants may surrender shares of our common stock as payment of applicable tax withholding obligations in connection with the vesting of shares of restricted stock and/or the exercise of stock options. These shares are not repurchased pursuant to a publicly announced share repurchase program.

Item 6. Exhibits

3.1 Amended and Restated Articles of Incorporation filed November 2, 2005 with the Secretary of State of the state of Georgia (incorporated herein by reference to Exhibit 3.1 of AGL Resources Inc. Current Report on Form 8-K dated November 2, 2005).

3.2 Bylaws, as amended on October 29, 2003 (incorporated herein by reference to Exhibit 3.2 of AGL Resources Inc. Annual Report on Form 10-K for the fiscal year ended December 31, 2003).

10.1 Credit Agreement as of August 31, 2006, by and among AGL Resources Inc., AGL Capital Corporation, SunTrust Bank, as administrative agent, Wachovia Bank, National Association, as syndication agent, JPMorgan Chase Bank, N.A., The Bank of Tokyo-Mitsubishi UFJ, Ltd. and Calyon New York Branch, as co-documentation agents, and the several other banks and other financial institutions named therein (incorporated herein by reference to Exhibit 10 of AGL Resources Inc. Current Report on Form 8-K dated August 31, 2006).

31.1 Certification of John W. Somerhalder II pursuant to Rule 13a – 14(a)

31.2 Certification of Andrew W. Evans pursuant to Rule 13a – 14(a)

32.1 Certification of John W. Somerhalder II pursuant to 18 U.S.C. Section 1350

32.2 Certification of Andrew W. Evans pursuant to 18 U.S.C. Section 1350

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 thereunto duly authorized.

AGL RESOURCES INC.
(Registrant)

Date: October 26, 2006

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