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PUBLIC SERVICE
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BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

IN THE MATTER OF	**) CASE NO. 2006-00464**
RATE APPLICATION BY	**)**
ATMOS ENERGY CORPORATION	**)**
MID-STATES/KENTUCKY	**)**

RESPONSE OF ATMOS ENERGY CORPORATION, KENTUCKY TO

KPSC DATA REQUEST DATED FEBRUARY 23, 2007

(KPSC DATA REQUEST NO. 2)

DR 37

MARCH 16, 2007

Atmos Energy
Case No 2006-0046
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Atmos Energy Corporation, Kentucky
Case No. 2006-00464
KPSC 2nd Data Request Dated February 23, 2007
DR Item 37
Witness: Don Murry

Data Request:

Refer to the Murry Testimony, pages 13 and 14.

a. Provide a copy of the most recent Value Line company profile discussions for each of the companies that Dr. Murry selected as being comparable to Atmos.

b. For Atmos and each of the comparable companies, provide for the most recent year available a breakout of revenue derived from state regulated distribution operations, other regulated operations, and non-utility operations.

Response:

a. Please see the attached.

b. The attached file separates revenues by segment for Atmos and the comparable companies as reported in their most recent 10-K annual reports.

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 32.82 | P/E RATIO 14.1 (Trailing: 17.9 / Median: 16.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 3.9% | VALUE LINE 461

TIMELINESS 3 Raised 7/28/06
SAFETY 2 Raised 12/16/05
TECHNICAL 2 Raised 11/17/06
BETA .80 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	8%
Low	30	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	1.0	1	1.0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	93	89	102
to Sell	91	84	67
Hld's(000)	43022	46004	46293

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
..... Relative Price Strength
3-for-2 split 5/94
Options: No
Shaded area indicates recession

High: 23.0 31.0 30.5 32.3 33.0 26.3 25.8 24.5 25.5 27.6 30.0 33.1
Low: 16.1 20.9 22.1 24.8 19.6 14.3 19.5 17.6 20.8 23.4 25.0 25.5

Target Price Range 2009 | 2010 | 2011

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.0	15.5
3 yr.	52.6	49.4
5 yr.	112.8	85.9

Percent shares traded: 12 / 8 / 4

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

CAPITAL STRUCTURE as of 6/30/06
Total Debt $2481.2 mill. Due in 5 Yrs $860.0 mill.
LT Debt $2180.8 mill. LT Interest $135.0 mill.
(LT interest earned: 2.7x; total interest coverage: 2.6x)
, Uncapitalized Annual rentals $15.3 mill.
ck None
on Assets-9/05 $355.9 mill. Oblig. $359.9 mill.
Common Stock 81,595,723 shs.
as of 7/31/06
MARKET CAP: $2.7 billion (Mid Cap)

CURRENT POSITION (SMILL.)

	2004	2005	6/30/06
Cash Assets	201.9	40.1	26.8
Other	475.2	1224.3	1023.4
Current Assets	677.1	1264.4	1050.2
Accts Payable	185.3	461.3	306.8
Debt Due	5.9	148.1	300.4
Other	223.3	503.4	407.6
Current Liab.	414.5	1112.8	1014.8
Fix. Chg. Cov.	364%	395%	400%

ANNUAL RATES of change (per sh)

	10 Yrs.	5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	6.0%	16.5%	10.5%
"Cash Flow"	3.5%	2.0%	6.5%
Earnings	4.0%	6.5%	6.5%
Dividends	3.0%	2.0%	2.0%
Book Value	5.5%	8.5%	4.0%

QUARTERLY REVENUES ($ mill.) A

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	680.4	1194.1	486.5	436.9	2799.9
2004	763.6	1117.5	546.1	492.8	2920.0
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	*1550*	*1550*	*1550*	*1550*	*6200*

EARNINGS PER SHARE A B E

Fiscal Year Ends	Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.60	1.24	.07	d.05	1.71
2004	.57	1.12	.09	d.11	1.58
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	.25	2.00
2007	*.85*	*1.15*	*.08*	*d.13*	*1.95*

QUARTERLY DIVIDENDS PAID C■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.295	.295	.295	.30	1.19
2003	.30	.30	.30	.305	1.21
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	©VALUE LINE PUB., INC.	09-11
	30.19	30.59	27.90	22.09	26.61	35.36	22.82	54.39	46.50	61.75	*75.05*	*73.80*	Revenues per sh A	*100.00*
	2.80	2.85	3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	*4.25*	*4.30*	"Cash Flow" per sh	*4.85*
	1.51	1.34	1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	*2.00*	*1.85*	Earnings per sh A B	*2.45*
	.96	1.01	1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	*1.26*	*1.28*	Div'ds Decl'd per sh C■	*1.35*
	4.84	4.13	4.44	3.59	2.36	2.77	3.17	3.10	3.03	4.14	*5.20*	*5.15*	Cap'l Spending per sh	*7.10*
	10.75	11.04	12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	*20.10*	*20.20*	Book Value per sh	*22.95*
	16.02	29.64	30.40	31.25	31.95	40.79	41.68	51.48	62.80	80.54	*82.00*	*84.00*	Common Shs Outst'g D	*100.00*
	15.1	17.9	15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5		Avg Ann'l P/E Ratio	*14.0*
	.95	1.03	.80	1.88	1.23	.80	.83	.76	.84	.84	.72		Relative P/E Ratio	*.95*
	4.2%	4.2%	3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%		Avg Ann'l Div'd Yield	*3.9%*
	483.7	906.8	848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	*6200*	Revenues ($mill) A	*10000*
	23.9	39.2	55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	*165*	Net Profit ($mill)	*250*
	35.7%	37.5%	36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	*37.5%*	Income Tax Rate	*36.0%*
	5.0%	4.3%	6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	*2.7%*	Net Profit Margin	*2.5%*
	41.5%	48.1%	51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	48.2%	57.7%	*57.0%*	*57.0%*	Long-Term Debt Ratio	*55.0%*
	58.5%	51.9%	48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	*43.0%*	*43.0%*	Common Equity Ratio	*45.0%*
	294.6	690.2	769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	*3830*	*3950*	Total Capital ($mill)	*5100*
	413.6	849.1	917.9	965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	*3630*	*3900*	Net Plant ($mill)	*5000*
	10.6%	8.3%	9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
	13.9%	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	6.5%	*10.0%*	*9.5%*	Return on Shr. Equity	*11.0%*
	13.9%	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	6.5%	*10.0%*	*9.5%*	Return on Com Equity	*11.0%*
	5.1%	3.9%	6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	*3.5%*	*3.5%*	Retained to Com Eq	*5.0%*
	64%	67%	58%	NMF	112%	79%	82%	70%	77%	73%	*64%*	*65%*	All Div'ds to Net Prof	*54%*

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via seven regulated natural gas utility operations: Louisiana Division, Mid-States Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky Division. Combined 2005 gas volumes: 295 MMcf. Breakdown: 55%, residential; 31%, commercial; 10%, industrial; and 4% other. 2005 depreciation rate 3.7%. Has around 4,330 employees. Officers and directors own approximately 2.6% of common stock (12/05 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

We believe that Atmos Energy's bottom line will be flat in fiscal 2007, which began on October 1st. This is attributable largely to the difficult comparison, reflecting a record performance from the non-utility marketing segment, which was able to capture highly favorable arbitrage spreads created by natural gas volatility. Note, too, that our figure for the fourth quarter of fiscal 2006 does not include an $0.18-a-share charge for the impairment of irrigation properties in the West Texas Division.

But the company ought to be aided by certain factors. Weather-normalized rates are now in effect for the Mid-Tex operation and Louisiana unit, presently accounting for almost 60% of the customer base, combined. Consequently, around 90% of the utility's margins are protected by these mechanisms, compared to about 33% previously. Also, this fiscal year's results should be absent the $0.10-a-share reduction from the impact of Hurricane Katrina.

Atmos is one of the more aggressively managed natural gas utilities in the *Value Line* universe, as it has completed a string of major acquisitions over the past 20 years (the last one being TXU Gas Company in 2004). The TXU purchase brought a substantial pipeline business into the fold. The company is now one of the largest operators in Texas, with room for expansion. Management will undoubtedly continue to implement its strategy of purchasing less-efficient utilities and shoring up their profitability through expense-reduction initiatives, rate relief, and aggressive marketing efforts.

These good-quality shares have exhibited strength since our last report in September, arising partly, we think, from the possibility that natural gas costs will decline this winter, in view of weather forecasts and supply levels.

Income-oriented accounts may be drawn to the dividend yield. And it seems that more increases in the payout are plausible. Earnings coverage should remain adequate.

But long-term total-return possibilities are limited, given the stock's price move. Also, the Timeliness rank is just 3 (Average).

Frederick L. Harris, III December 15, 2006

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	70

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '97, d53¢; '99, d23¢; '00, 12¢; '03, d17¢; Q4 '06, d18¢. Next egs. rpt. due early Feb. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan: Direct stock purchase plan avail. (D) In millions, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

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AGL RESOURCES NYSE-ATG

RECENT PRICE 39.50 | P/E RATIO 14.8 (Trailing: 13.3 / Median: 14.0) | RELATIVE P/E RATIO 0.80 | DIV'D YLD 4.0% | VALUE LINE 460

TIMELINESS 4 Lowered 8/11/06
SAFETY 2 New 7/27/80
TECHNICAL 2 Raised 12/1/06
BETA .95 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	35	(-10%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	1	0	0	0	0	1	0
to Sell	0	0	1	0	0	0	0	2	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	109	110	95
to Sell	88	83	102
Hld's(000)	49186	45106	49525

LEGENDS
1.15 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 12/95
Options: Yes
Shaded area indicates recession

	2002	2003	2004	2005	2006	2007
High:	20.0	22.0	21.6	23.4	23.4	25.0
Low:	14.9	17.1	17.8	17.7	15.6	15.5

	2008	2009	2010	2011
High:	29.3	33.7	39.3	40.0
Low:	21.9	26.5	32.0	34.4

Target Price Range 2009 | 2010 | 2011

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.2	15.5
3 yr.	52.1	49.4
5 yr.	120.8	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
22.53	20.26	20.43	22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	*35.55*	*36.10*	Revenues per sh [A]	*38.30*
2.04	2.07	2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	*4.40*	*4.50*	"Cash Flow" per sh	*4.85*
1.01	1.04	1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	*2.65*	*2.70*	Earnings per sh [A B]	*2.90*
.98	1.02	1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	*1.50*	*1.58*	Div'ds Decl'd per sh [C]	*1.75*
2.73	2.95	2.74	2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	*3.20*	*3.10*	Cap'l Spending per sh	*2.25*
8.97	9.42	9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	*20.40*	*21.50*	Book Value per sh [D]	*25.10*
44.32	47.57	48.69	49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	*77.90*	*78.00*	Common Shs Outst'g [E]	*78.30*
14.2	15.3	15.5	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
1.05	.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76			Relative P/E Ratio	*1.00*
6.8%	6.4%	5.9%	5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%			Avg Ann'l Div'd Yield	*4.0%*
1220.2	1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	*2770*	*2815*	Revenues ($mill) [A]	*3000*
75.6	76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	*205*	*210*	Net Profit ($mill)	*230*
38.6%	37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
6.2%	5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	*7.5%*	*7.5%*	Net Profit Margin	*7.7%*
46.2%	48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	*51.0%*	*50.0%*	Long-Term Debt Ratio	*48.5%*
48.9%	45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	*49.0%*	*50.0%*	Common Equity Ratio	*51.5%*
1201.3	1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	*3225*	*3310*	Total Capital ($mill)	*3775*
1415.4	1496.6	1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	*3350*	*3450*	Net Plant ($mill)	*3750*
8.0%	7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	*8.0%*	*8.0%*	Return on Total Cap'l	*7.5%*
11.7%	11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	*13.0%*	*12.5%*	Return on Shr. Equity	*12.0%*
12.1%	11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	*13.0%*	*12.5%*	Return on Com Equity	*12.0%*
3.8%	3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.8%	5.6%	6.2%	*5.5%*	*5.5%*	Retained to Com Eq	*5.0%*
71%	74%	64%	101%	72%	65%	52%	53%	49%	52%	*57%*	*58%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt 2075.0 mill. Due in 5 Yrs $530.0 mill.
LT Debt $1634.0 mill. LT Interest $100.0 mill.

(Total interest coverage: 4.4x)
Leases, Uncapitalized Annual rentals $27.0 mill.

Pension Assets-12/05 $371.0 mill.
Oblig. $464.0 mill.

Pfd Stock None
Common Stock 77,696,090 shs.
as of 10/20/06

MARKET CAP: $3.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	49.0	30.0	14.0
Other	1408.0	2002.0	1498.0
Current Assets	1457.0	2032.0	1512.0
Accts Payable	207.0	264.0	540.0
Debt Due	334.0	522.0	441.0
Other	936.0	1153.0	335.0
Current Liab.	1477.0	1939.0	1316.0
Fix. Chg. Cov.	510%	442%	470%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	1.0%	7.0%	*7.5%*
"Cash Flow"	5.0%	7.0%	*5.0%*
Earnings	6.5%	13.5%	*4.0%*
Dividends	1.5%	2.0%	*6.5%*
Book Value	5.5%	8.5%	*6.5%*

Calendar	QUARTERLY REVENUES ($ mill.) [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	352.5	186.6	166.3	278.3	983.7
2004	651.0	294.0	262.0	625.0	1832.0
2005	908.0	430.0	387.0	993.0	2718.0
2006	1047.0	436.0	434.0	*853*	*2770*
2007	*970*	*480*	*465*	*900*	*2815*

Calendar	EARNINGS PER SHARE [A B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.98	.29	.27	.54	2.08
2004	1.00	.33	.31	.64	2.28
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.46	*.53*	*2.65*
2007	*1.30*	*.37*	*.29*	*.74*	*2.70*

Calendar	QUARTERLY DIVIDENDS PAID [C] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.27	.27	.27	.27	1.08
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries are Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia (primarily Atlanta), Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acq. Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common; Goldman Sachs, 5.5%; JPMorgan, 5.9% (3/06 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: 10 Peachtree Place N.E., Atlanta, GA 30309. Tel.: 404-584-4000. Internet: www.aglresources.com.

AGL Resources is on track to register solid earnings gains in 2006. The company reported earnings of $0.46 a share in the third quarter, significantly ahead of the prior year. Most of the gains can be attributed to a strong performance at the company's Wholesale Services segment. The unit benefited from mark-to-market gains following the decline in NYMEX gas prices. This resulted in the recognition of $38 million in gains compared to the loss of $46 million last year when gas prices increased significantly. Since gas prices typically fluctuate over time, quarterly earnings should remain volatile at this unit.

The company is looking to reduce costs about 2%–3% at its distribution segment. Over the past few years, operating and maintenance costs per customer have decreased significantly thanks to numerous efficiency programs put in place. As another way to improve results, the company is looking to reduce customer attrition. Management believes it can achieve 0.8% growth this year and push the rate higher in the coming years.

No progress has been made on the Jefferson Island storage facility dispute since our last report. In August, the Louisiana Department of Natural Resources terminated the company's mineral lease. AGL Resources responded by filing suit in September against the state of Louisiana to maintain its lease and complete the project. Management is optimistic that a resolution can be reached, though the third cavern will likely not become operational until 2009 as a result of delays. In addition,

The company has signed an option to develop a salt dome in east Texas near the Gulf Coast. It has an estimated 12 billion cubic feet of working capacity. The location also provides the ability to connect to other pipelines in the area, along with potential LNG facilities that may come into the region. The first cavern, which would be about six bcf and similar in size to the Jefferson Island cavern, has the potential to be in operation by 2010.

Though untimely, this stock offers a good dividend yield. ATG shares offer only limited appreciation potential, but further expansion in nonregulated activities may well improve these prospects.

Evan I. Blatter *December 15, 2006*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07). Next earnings report due late Jan.
(C) Dividends historically paid early March, June, Sept, and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2005: $422 million, $5.43/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

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NEW JERSEY RES. NYSE-NJR

RECENT PRICE **52.26** | P/E RATIO **18.9** (Trailing: 18.7 Median: 15.0) | RELATIVE P/E RATIO **1.03** | DIV'D YLD **2.9%** | VALUE LINE **465**

TIMELINESS **5** Lowered 12/15/06
SAFETY **1** Raised 9/15/06
TECHNICAL **3** Lowered 11/24/06
BETA .80 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+25%)	9%
Low	50	(-5%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	5	0	0	2	0	0	4	0
to Sell	0	4	0	0	2	0	0	4	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	64	71	73
to Sell	60	62	60
Hld's(000)	13455	14776	16255

LEGENDS
1.18 x Dividends p sh divided by Interest Rate
..... Relative Price Strength
3-for-2 split 3/02
Options: No
Shaded area indicates recession

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	
High:					20.3	19.9	28.0	26.8	27.4	29.8	32.5	33.6	39.5	44.6	48.3	53.2			Target Price Range 2009 2010 2011
Low:					14.3	17.9	18.8	21.0	22.4	24.1	24.8	24.3	30.0	36.5	40.7	41.5			
	16.01	15.99	16.88	18.02	19.22	17.03	20.22	25.97	26.59	33.98	44.13	76.82	66.17	93.43	91.33	114.29	119.44	*121.45*	Revenues per sh A
	1.54	1.58	1.95	2.14	2.31	2.13	2.22	2.45	2.60	2.79	2.99	3.18	3.21	3.58	3.75	3.92	4.10	*4.20*	"Cash Flow" per sh
	.65	.55	1.09	1.15	1.26	1.29	1.37	1.48	1.55	1.66	1.79	1.95	2.09	2.38	2.55	2.65	2.80	*2.90*	Earnings per sh B
	.96	1.00	1.01	1.01	1.01	1.01	1.03	1.07	1.09	1.12	1.15	1.17	1.20	1.24	1.30	1.36	1.44	*1.52*	Div'ds Decl'd per sh C
	4.37	2.91	1.99	2.31	2.10	1.77	1.78	1.72	1.60	1.81	1.85	1.66	1.53	1.71	2.17	1.92	1.92	*1.95*	Cap'l Spending per sh
	8.85	8.57	9.44	9.81	9.64	9.70	10.10	10.38	10.88	11.35	12.43	13.20	13.06	15.38	16.87	15.90	22.50	*23.60*	Book Value per sh
	20.28	20.95	24.43	25.23	25.95	26.69	27.13	26.82	26.72	26.61	26.39	26.66	27.67	27.23	27.74	27.55	27.69	*28.00*	Common Shs Outst'g D
	24.0	22.3	12.4	15.1	13.0	11.7	13.5	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1		Avg Ann'l P/E Ratio
	1.78	1.42	.75	.89	.85	.78	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.86		Relative P/E Ratio
	6.2%	8.1%	7.5%	5.8%	6.2%	6.7%	5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%		Avg Ann'l Div'd Yield
	548.5	696.5	710.3	904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	*3400*	Revenues ($mill) A
	38.7	41.5	43.3	44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	*82.0*	Net Profit ($mill)
	32.6%	33.3%	30.4%	36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	*39.0%*	Income Tax Rate
	7.1%	6.0%	6.1%	5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	*2.4%*	Net Profit Margin
	50.7%	49.3%	51.2%	48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	*34.0%*	Long-Term Debt Ratio
	45.8%	47.1%	45.6%	51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	*66.0%*	Common Equity Ratio
	598.2	590.6	638.2	590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	*1080*	Total Capital ($mill)
	655.2	659.4	680.0	705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	*970*	Net Plant ($mill)
	8.1%	8.6%	8.1%	9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	*9.5%*	Return on Total Cap'l
	13.1%	13.9%	13.9%	14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	*12.5%*	Return on Shr. Equity
	13.5%	14.3%	14.4%	14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	*12.5%*	Return on Com Equity
	3.4%	4.0%	4.4%	5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	*6.0%*	Retained to Com Eq
	76%	73%	71%	67%	63%	59%	56%	51%	49%	50%	50%	*52%*	All Div'ds to Net Prof

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	25.7	15.5
3 yr.	48.3	49.4
5 yr.	96.2	85.9

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CAPITAL STRUCTURE as of 9/30/06
Total Debt $616.8 mill. Due In 5 Yrs $300.0 mill.
LT Debt $332.4 mill. LT Interest $25.0 mill.
Incl. $7.4 mill. capitalized leases.
(total interest coverage: 6.0x)
Pension Assets-9/06 $95.8 mill. Oblig. $103.7 mill.

Pfd Stock None

Common Stock 27,676,310 shs.
as of 11/20/06
MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	5.0	25.0	5.0
Other	681.0	927.8	960.5
Current Assets	686.0	952.8	965.5
Accts Payable	42.9	54.7	46.8
Debt Due	267.4	177.4	284.4
Other	357.4	744.2	566.0
Current Liab.	667.7	976.3	897.2
Fix. Chg. Cov.	826%	660%	571%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '09-'11
Revenues	19.0%	16.0%	*3.5%*
"Cash Flow"	6.0%	5.5%	*4.0%*
Earnings	7.5%	8.0%	*4.5%*
Dividends	9.0%	3.5%	*4.5%*
Book Value	6.5%	8.5%	*8.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A				Full Fiscal Year
	Dec.31	Mar.31	Jun.30	Sep.30	
2003	668.8	1152	369.7	353.1	2544.4
2004	643.0	1037	438.5	414.4	2533.6
2005	854.0	1065	544.3	684.9	3148.3
2006	1164	1064	536.1	534.5	3299.6
2007	*1085*	*1150*	*610*	*555*	*3400*

Fiscal Year Ends	EARNINGS PER SHARE A B				Full Fiscal Year
	Dec.31	Mar.31	Jun.30	Sep.30	
2003	.85	1.50	.16	d.13	2.38
2004	.87	1.82	.06	d.20	2.55
2005	.91	1.84	.07	d.17	2.65
2006	1.23	2.14	d.14	d.43	2.80
2007	*1.18*	*1.95*	*.07*	*d.30*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■				Full Year
	Mar.31	Jun.30	Sep.30	Dec.31	
2002	.30	.30	.30	.30	1.20
2003	.31	.31	.31	.31	1.24
2004	.325	.325	.325	.325	1.30
2005	.34	.34	.34	.34	1.36
2006	.36	.36	.36	.36	1.44

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Next earnings report due late Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) In millions, adjusted for split.

BUSINESS: New Jersey Resources Corp. is a holding company providing retail and Wholesale energy svcs. to customers in New Jersey, in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas has about 471,000 customers at 9/30/06 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2006 volume: 102.8 bill. cu. ft. (56% firm, 7% interruptible industrial and electric utility, 37% off-system and capacity release). N.J. Natural Energy subsid. provides unregulated retail and wholesale natural gas and related energy svcs. 2006 dep. rate: 2.7%. Has 766 employ. Off./dir. own about 3% of common (12/05 Proxy). Chmn. and CEO: Laurence M. Downes, Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1000. Web: www.njliving.com.

We think New Jersey Resources' share earnings will advance only moderately in fiscal 2007 (year ends September 30th). Results at the company's main subsidiary, New Jersey Natural Gas (NJNG), should be helped by the approval of a conservation incentive plan (CIP) in October by the New Jersey Board of Public Utilities. The CIP is a three-year pilot program that protects against both warmer-than-normal temperatures and conservation by customers, unlike the previous weather normalization clause that only protected against warmer temperatures. This will enable NJNG to promote conservation and efficiency, while protecting its financial performance. Customer growth remains strong. The company added about 10,160 customers in 2006 (to a total of around 470,000), with almost 35% converting from other fuels, and we look for similar levels of growth this year.

The company's results were once again led by the Energy subsidiaries good performance. For the year, the division reported earnings of $28 million, more than 70% above the year-ago period. The strong performance helped offset results at NJNG, where earnings were hurt by reduced customer usage. The increase in earnings at the Energy unit was primarily due to favorable spreads on its storage asset positions. This can be attributable to the fact that the company's holding facilities become more valuable when prices change between areas and/or time periods. In addition, results from this segment are typically better during the winter months, since the fixed costs of these assets are spread throughout the entire year.

Though untimely, this good-quality stock generates consistent results. The board recently raised the quarterly dividend by 5.6%, to $0.38 a share. We look for further modest increases over the next few years. However, the yield is below that of its utility counterparts, partly owing to good customer growth prospects. The lower yield is also due to funds being used for nonutility investments. For 2007, these activities may comprise 25%–30% of total earnings. However, investors should be aware that these activities are more risky than regulated operations.

Evan I. Blatter — *December 15, 2006*

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	100

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NICOR, INC. NYSE-GAS

RECENT PRICE 49.59 | P/E RATIO 18.1 (Trailing: 18.0 / Median: 14.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 3.8% | VALUE LINE 466

TIMELINESS 2 Raised 11/10/06
SAFETY 3 Lowered 6/17/05
TECHNICAL 2 Raised 11/3/06
BETA 1.30 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	6%
Low	35	(-30%)	-4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	1	0	0	1	0	0	1	1	3
Options	0	0	2	0	0	0	0	2	0
to Sell	0	0	2.0	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	117	112	98
to Sell	97	94	110
Hld's(000)	30966	32681	32450

High: 28.5 37.1 42.9 44.4 42.9 43.9 42.4 49.0 39.3 39.7 43.0 49.9
Low: 21.8 25.4 30.0 37.1 31.2 29.4 34.0 17.3 23.7 32.0 35.5 38.7

LEGENDS
1.30 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 4/93
Options: Yes
Shaded area indicates recession

Target Price Range 2009 | 2010 | 2011

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.3	15.5
3 yr.	75.0	49.4
5 yr.	63.0	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
26.52	26.46	28.90	31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	76.00	*71.90*	*72.30*	Revenues per sh	*71.25*
3.86	3.92	4.14	3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.19	*5.95*	*6.10*	"Cash Flow" per sh	*6.15*
1.93	1.86	1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.27	*2.70*	*2.72*	Earnings per sh [A]	*2.80*
1.06	1.12	1.18	1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	*1.86*	*1.90*	Div'ds Decl'd per sh [B] ■	*2.00*
3.00	3.65	3.12	2.62	3.34	3.12	2.42	2.34	2.87	3.26	3.48	4.18	4.37	4.12	4.32	4.57	*4.50*	*4.50*	Cap'l Spending per sh	*4.45*
11.67	12.28	12.76	13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	18.36	*19.35*	*20.20*	Book Value per sh	*22.80*
57.93	57.30	55.77	53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.18	*44.50*	*44.50*	Common Shs Outst'g [C]	*44.90*
10.7	11.5	11.6	14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	17.3	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*16.0*
.79	.73	.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.91			Relative P/E Ratio	*1.05*
5.1%	5.2%	5.3%	4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	4.7%			Avg Ann'l Div'd Yield	*4.5%*
						1850.7	1992.6	1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	*3200*	*3225*	Revenues ($mill)	*3200*
						121.2	124.3	111.1	121.9	136.4	136.3	128.0	93.1	98.1	101.1	*120*	*120*	Net Profit ($mill)	*125*
						35.8%	35.0%	34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	*27.0%*	*30.0%*	Income Tax Rate	*32.0%*
						6.5%	6.2%	7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	*3.8%*	*3.8%*	Net Profit Margin	*3.9%*
						41.3%	42.3%	42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	*34.0%*	*33.0%*	Long-Term Debt Ratio	*31.0%*
						58.1%	57.2%	57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	*66.0%*	*67.0%*	Common Equity Ratio	*69.0%*
						1255.1	1300.6	1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	*1310*	*1350*	Total Capital ($mill)	*1475*
						1771.9	1735.8	1731.8	1735.2	1729.6	1768.6	1798.8	2484.2	2549.8	2659.1	*2760*	*2860*	Net Plant ($mill)	*3160*
						11.1%	11.1%	9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	*10.9%*	*10.6%*	Return on Total Cap'l	*10.0%*
						16.4%	16.6%	14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	*14.0%*	*13.5%*	Return on Shr. Equity	*12.0%*
						16.6%	16.7%	14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	*14.0%*	*13.0%*	Return on Com Equity	*12.0%*
						7.6%	7.6%	5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
						54%	55%	63%	60%	56%	58%	63%	88%	84%	81%	*68%*	*70%*	All Div'ds to Net Prof	*72%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $660.4 mill. Due in 5 Yrs $215.0 mill.
LT Debt $459.4 mill. LT Interest $20.0 mill.
(Total interest coverage: 4.0x)

Pension Assets-12/05 $424.0 mill. Oblig. $284.4 mill.

Pfd Stock $.6 mill. Pfd Div'd $2.2 mill.
(11,681 shares of 4.48% mandatorily redeemable preferred stock)
Common Stock 44,709,976 shares
as of 10/27/06
MARKET CAP: $2.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)

	2004	2005	9/30/06
Cash Assets	83.2	126.9	54.4
Other	937.7	1218.8	628.2
Current Assets	1020.9	1345.7	682.6
Accts Payable	502.9	658.2	519.4
Debt Due	490.2	636.0	201.0
Other	178.3	328.7	263.0
Current Liab.	1171.4	1622.9	983.4
Fix. Chg. Cov.	428%	367%	NMF

ANNUAL RATES (of change (per sh))

	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	8.0%	11.5%	*1.0%*
"Cash Flow"	4.0%	0.5%	*1.0%*
Earnings	1.0%	-3.5%	*4.0%*
Dividends	4.0%	3.5%	*1.0%*
Book Value	3.0%	1.5%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1171.3	452.8	294.8	743.8	2662.7
2004	1115.7	429.5	299.9	894.6	2739.7
2005	1179.9	484.4	336.0	1357.5	3357.8
2006	1319.4	451.3	351.1	*1078.2*	*3200*
2007	*1250*	*500*	*350*	*1125*	*3225*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1.11	.21	d.01	.78	2.11
2004	.96	.44	d.26	1.08	2.22
2005	.98	.35	d.06	1.02	2.27
2006	.94	.41	.39	*.96*	*2.70*
2007	*1.02*	*.37*	*.28*	*1.05*	*2.72*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.46	.46	.46	.46	1.84
2003	.46	.465	.465	.465	1.86
2004	.465	.465	.465	.465	1.86
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.1 million customers in northern and western Illinois. 2005 gas delivered: 470.6 Bcf, incl. 219.4 Bcf from transportation. 2005 gas sales (251.2 bcf): residential, 80%; commercial, 18%; industrial, 2%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,700 employees Off./dir. own about 2.8% of common stock. (3/06 proxy). Chairman and CEO: Russ Strobel. Inc.: Illinois Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor reported strong results for its September period. Indeed, the company registered a share-net gain of $0.39, which exceeded the popular consensus and topped last year's number at a loss of $0.06 a share. All operating segments produced solid results. However, volumes were particularly strong in the gas distribution segment.

As the unseasonably warm weather passes, the company will likely benefit from an increase in the usage of natural gas over the balance of the year. The industry suffered through a tough first half due to warm conditions, but now as we near 2007, gas deliveries are increasing. As gas consumption returns to normal levels, Nicor's bottom line should push forward, beginning in 2007.

Base rates will likely remain unchanged. Late in 2005, the Illinois Commerce Commission approved an increase in rates, which will likely continue to help the company's top and bottom lines in 2007. For the near term, Nicor seems to be content to move forward operating in the current conditions. Still, it has not fully utilized strategies that would protect its business through various mechanisms, which would help limit the variability of earnings. Thus, we anticipate similar volatility for these shares in the future.

Nicor's other business segments should continue to be solid. Particularly, the Tropical Shipping division has continued to generate high revenues, which ought to continue going into 2007, as demand for the service remains robust. The company's energy ventures ought to also add some consistent volume to Nicor's top line over the next year.

This issue is ranked to outperform the market in the year ahead. All told, the company has taken steps to improve its business across all of its segments and has benefited from the latest rate increase. However, much of this issue's long-term appreciation potential has been realized, as this stock is already trading within its Target Price Range.

These shares may be of interest to income-oriented investors. Although Nicor offers a yield that is slightly below the industry mean at 3.8%, it's still is above the *Value Line* average.

Richard Gallagher *December 15, 2006*

Company's Financial Strength	A
Stock's Price Stability	55
Price Growth Persistence	35
Earnings Predictability	80

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '89, 7¢; '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Quarterly earnings may not sum to total due to rounding. Next egs. report due early March. (B) Dividends historically paid early February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions, adjusted for stock split.

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W. NAT'L GAS NYSE-NWN

RECENT PRICE 41.62 | P/E RATIO 17.9 (Trailing: 19.5 Median: 15.0) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.4% | VALUE LINE 467

TIMELINESS 4 Lowered 12/8/06
SAFETY 1 Raised 3/18/05
TECHNICAL 2 Raised 12/8/06
BETA .75 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	5%
Low	40	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	0	0	0	0	1	0	0	0	1

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	59	62	77
to Sell	54	59	59
Hld's(000)	12922	13095	14328

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
Relative Price Strength
3-for-2 split 9/95
Options: Yes
Shaded area indicates recession

Target Price Range 2009 | 2010 | 2011

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	24.6	15.5
3 yr.	52.1	49.4
5 yr.	105.7	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
17.02	16.74	14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	26.07	23.57	25.69	33.01	*36.35*	*35.65*	Revenues per sh	*51.80*
3.22	2.57	3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	*4.65*	*4.75*	"Cash Flow" per sh	*5.10*
1.62	.67	.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	*2.25*	*2.40*	Earnings per sh [A]	*2.85*
1.10	1.13	1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	*1.39*	*1.43*	Div'ds Decl'd per sh [B■]	*1.70*
3.85	3.58	3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.76	3.46	3.23	3.11	4.90	5.52	3.48	*3.65*	*3.30*	Cap'l Spending per sh	*3.35*
12.61	12.23	12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	*22.10*	*22.95*	Book Value per sh	*25.55*
17.41	17.68	19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	*27.50*	*27.80*	Common Shs Outst'g [C]	*28.00*
10.2	28.1	27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.76	1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91			Relative P/E Ratio	*1.00*
6.7%	5.9%	5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%			Avg Ann'l Div'd Yield	*4.0%*
						380.3	361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	910.5	*1000*	*1025*	Revenues ($mill)	*1350*
						46.8	43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	*62.0*	*65.5*	Net Profit ($mill)	*80.0*
						36.9%	32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
						12.3%	11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	*6.2%*	*6.5%*	Net Profit Margin	*5.9%*
						41.4%	46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*47%*
						52.8%	49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	*53.0%*	*53.0%*	Common Equity Ratio	*53%*
						657.4	748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	*1125*	*1175*	Total Capital ($mill)	*1350*
						745.3	827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	*1425*	*1475*	Net Plant ($mill)	*1700*
						8.9%	7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
						12.1%	10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.5%*
						12.7%	11.0%	8.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	*10.0%*	*10.5%*	Return on Com Equity	*10.5%*
						5.0%	3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	*3.7%*	*3.7%*	Retained to Com Eq	*3.8%*
						63%	70%	118%	74%	70%	67%	79%	72%	69%	63%	*62%*	*59%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $624.8 mill. Due in 5 Yrs $251.7 mill.
LT Debt $492.0 mill. LT Interest $31.0 mill.
(Total interest coverage: 3.4x)
Pension Assets-12/05 $218.6 mill.
Oblig. $267.9 mill.
Pfd Stock None
Common Stock 27,504,896 shs.
as of 10/31/06
MARKET CAP: $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	5.2	7.1	5.7
Other	231.9	316.6	209.7
Current Assets	237.1	323.7	215.4
Accts Payable	102.5	135.3	64.5
Debt Due	117.5	134.7	132.8
Other	47.3	56.6	58.6
Current Liab.	267.3	326.6	255.9
Fx. Chg. Cov.	316%	340%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	4.5%	6.0%	*11.0%*
"Cash Flow"	1.5%	2.5%	4.5%
Earnings	1.5%	5.0%	7.0%
Dividends	1.0%	1.0%	4.0%
Book Value	4.0%	3.5%	3.5%

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	206.5	117.5	69.5	217.8	611.3
2004	254.5	109.7	81.4	262.0	707.6
2005	308.7	153.7	106.7	341.4	910.5
2006	390.4	171.0	114.9	*323.7*	*1000*
2007	*370*	*180*	*135*	*340*	*1025*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1.01	.17	d.25	.83	1.76
2004	1.24	d.03	d.30	.95	1.86
2005	1.44	.04	d.31	.94	2.11
2006	1.48	.07	d.35	*1.05*	*2.25*
2007	*1.55*	*.06*	*d.33*	*1.11*	*2.40*

Calendar	QUARTERLY DIVIDENDS PAID [B■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.315	.315	.315	.315	1.26
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due early February.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock split.

BUSINESS: Northwest Natural Gas Co. distributes natural gas at retail to 90 communities, 624,000 customers, in Oregon (90% of custs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system to bring gas to market. Owns local underground storage. Rev. breakdown: residential, 53%; commercial, 27%; industrial, gas transportation, and other, 20%. Employs 1,305. Barclays owns 6.2% of shares; insiders, 1% (4/06 proxy). CEO: Mark S. Dodson, Inc.: OR. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest reported a seasonal loss in the third quarter. The increased loss was due largely to the effects of the company's weather adjustment clause, which cost about $0.02 in the September period, and to the fact that some industrial customers switched to lower rate schedules. Meanwhile, customer growth for the last 12 months was strong, at 3.4%.

We look for a solid earnings gain in the fourth quarter due in part to the absence of an unusual expense. In the final period of 2005, unusual litigation costs reduced earnings by $0.05 a share, which Northwest will not incur this year. Customer growth should add a few cents a share. Moreover, changes in the company's weather adjustment clause have moved the effective date back to October 1st, which give Northwest protection against warm weather in October and November for the first time. The first severance costs of the company's new operations streamlining plan will occur in the December period, but they should be offset by gains coming from sales of some non-core assets.

Continued customer growth and cost cutting will likely produce decent earnings growth in 2007. The pace of new single-home construction is likely to slow, but growth from new apartment houses in Portland will offset much of that. And conversions from oil will probably grow, if, as we believe likely, OPEC keeps the price of oil over $55 a barrel. Too, Northwest's program to pare costs to equal the top quartile of all gas utilities should begin to pay off next year.

Earnings growth at an above-industry pace looks likely out to 2009-2011. A zoning change east of Portland should lead to substantial growth in residential customers by the end of our time horizon. It is likely that the growing demand for natural gas will bring at least one new liquefied natural gas plant to Northwest's territory. Moreover, a new pipeline connection could boost gas supplies. Still,

These untimely, but top-quality, shares, have below-average total return potential. Earnings and dividends will probably grow faster than the industry averages, but the likelihood of higher interest rates limits capital appreciation potential.

Sigourney B. Romaine December 15, 2006

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	75

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PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE 28.21 | P/E RATIO 19.6 (Trailing: 21.9 / Median: 17.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.4% | VALUE LINE 469

TIMELINESS 4 Raised 12/23/05
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 12/8/06
BETA .80 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+40%)	12%
Low	30	(+5%)	5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	10	9	9	9	9	9	10	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	1	1	0	1	2	0	0

Institutional Decisions

	3Q2005	1Q2006	2Q2006
to Buy	76	66	85
to Sell	77	71	61
Hld's(000)	30419	31060	32936

	High:	12.4	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.3			Target Price Range 2009	2010	2011
	Low:	9.1	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.8	19.2	21.3	23.2					

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 4/93
2-for-1 split 11/04
Options: No
Shaded area indicates recession

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	23.4	15.5
3 yr.	52.9	49.4
5 yr.	103.7	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
9.42	8.32	8.91	10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	*26.00*	*28.20*	Revenues per sh [A]	*33.10*
.97	.78	1.07	1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	*2.50*	*2.65*	"Cash Flow" per sh	*3.20*
.61	.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	*1.30*	*1.40*	Earnings per sh [B]	*1.75*
.42	.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	*.96*	*1.00*	Div'ds Decl'd per sh [C] ■	*1.17*
1.62	1.37	1.41	1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	*2.65*	*2.40*	Cap'l Spending per sh	*2.20*
4.58	4.83	5.13	5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	*11.90*	*12.40*	Book Value per sh [D]	*13.85*
42.87	49.48	51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	*75.00*	*74.50*	Common Shs Outst'g [E]	*72.50*
11.3	18.3	12.3	15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	*19.0*
.84	1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95			Relative P/E Ratio	*1.25*
6.0%	6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%			Avg Ann'l Div'd Yield	*3.5%*
						685.1	775.5	765.3	686.5	690.4	1107.9	832.0	1220.8	1529.7	1761.1	*1950*	*2100*	Revenues ($mill) [A]	*2400*
						46.6	55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	101.3	*100*	*105*	Net Profit ($mill)	*130*
						38.9%	39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	*35.0%*	*36.0%*	Income Tax Rate	*36.0%*
						7.1%	7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	*5.1%*	*5.1%*	Net Profit Margin	*5.3%*
						50.3%	47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	*48.0%*	*47.0%*	Long-Term Debt Ratio	*45.0%*
						49.7%	52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	*52.0%*	*53.0%*	Common Equity Ratio	*55.0%*
						777.1	800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	*1715*	*1750*	Total Capital ($mill)	*1830*
						862.0	941.7	990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	*2035*	*2170*	Net Plant ($mill)	*2400*
						8.2%	8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	*7.0%*	*7.5%*	Return on Total Cap'l	*8.0%*
						12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.5%*
						12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	*11.0%*	*11.5%*	Return on Com Equity	*12.5%*
						9.9%	4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	*3.0%*	*3.5%*	Retained to Com Eq	*4.5%*
						69%	65%	65%	72%	71%	75%	83%	74%	66%	68%	*72%*	*70%*	All Div'ds to Net Prof	*67%*

Percent shares traded: 7.5 / 5 / 2.5

2-for-1

CAPITAL STRUCTURE as of 7/31/06
Total Debt $927.5 mill. Due in 5 Yrs $325.0 mill.
LT Debt $825.0 mill. LT Interest $40.0 mill.
(LT Interest earned: 4.5x) total interest coverage: 4.5x)
Pension Assets-10/05 $199.2 mill. Oblig. $236.6 mill.
Pfd Stock None.
Common Stock 75,327,139 shs.
as of 9/1/06
MARKET CAP: $2.1 billion (Mid Cap)

CURRENT POSITION

($MILL.)	2004	2005	7/31/06
Cash Assets	5.7	7.1	8.5
Other	329.5	497.8	399.1
Current Assets	335.2	504.9	407.6
Accts Payable	99.6	182.8	64.9
Debt Due	109.5	193.5	102.5
Other	97.1	152.3	122.7
Current Liab.	306.2	528.6	290.1
Fix. Chg. Cov.	378%	400%	390%

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	11.0%	*6.5%*
"Cash Flow"	7.0%	5.5%	*6.0%*
Earnings	5.5%	5.0%	*6.0%*
Dividends	5.5%	5.0%	*5.5%*
Book Value	6.5%	6.5%	*3.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2003	493.5	407.8	140.1	179.4	1220.8
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	508.0	232.9	339.6	1761.1
2006	924.4	483.2	237.9	*307.5*	*1950*
2007	*875*	*565*	*315*	*345*	*2100*

Fiscal Year Ends	EARNINGS PER SHARE [A B F] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2003	.87	.47	d.15	d.08	1.11
2004	1.03	.54	d.11	d.21	1.27
2005	.93	.52	d.06	d.07	1.32
2006	.94	.57	d.16	*d.05*	*1.30*
2007	*.96*	*.57*	*d.05*	*d.09*	*1.40*

Calendar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.193	.20	.20	.20	.79
2003	.20	.208	.208	.208	.82
2004	.208	.215	.215	.215	.85
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 990,000 customers in North Carolina, South Carolina, and Tennessee. 2005 revenue mix: residential (39%), commercial (24%), industrial (13%), other (24%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 71.6% of revenues. '05 deprec. rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,125 employees. Officers & directors own less than 1% of common stock (1/06 proxy). CEO & President: Thomas E. Skains. Inc.: NC. Addr.: 1915 Rexford Road, P.O. Box 33068 Charlotte, NC 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Fiscal 2006 (began November 1st) will likely be a better year for Piedmont Natural Gas. Last year's results were impacted by a number of factors. The company benefited from increased margins due to growth in its residential and commercial customer base, along with the impact of changes in rates at two of its jurisdictions. However, this was offset by decreased customer consumption due to conservation, which probably contributed to the expected year-over-year earnings decline. This year, we look for earnings to advance about 5%–10%, driven by customer growth that should remain above the industry average, along with increased margins owing to the rate stabilization act in South Carolina that will result in a $6.5 million increase in revenue. Also, the company's restructuring efforts from last year should contribute $7 million to $7.5 million in annual cost savings.

The company is expanding its presence in nonregulated activities. During the first nine months of fiscal 2006, these activities contributed almost $28 million to earnings, 14% above last year. This includes its operations through SouthStar Energy, Pine Needle LNG, Cardinal Pipeline Company, and Hardy Storage Company. In addition, we look for Piedmont to continue to pursue investments in storage or pipeline assets to broaden its earnings stream.

Piedmont is diversifying its natural gas supply portfolio. Currently, the majority of the company's supply is derived from the Gulf Coast region. To reduce risk in the event of a shutdown, Piedmont has a firm transportation contract pending with Midwestern Gas Transmission Company for 128,000 dekatherms per day of additional capacity that will provide it access to the Canadian and Rocky mountain gas suppliers via the Chicago hub. Also, it has an agreement with Hardy Storage Company for storage capacity in its West Virginia region, which is scheduled to be in service in April, 2007.

Though untimely, this equity provides a good dividend yield. Risk is also limited, thanks to the stock's Above-Average Safety rank. Looking ahead, total-return potential is above that of the average utility stock covered by *Value Line*.

Evan I. Blatter *December 15, 2006*

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	80

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early Feb.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. At 10/31/05: $4.0 million, 5¢/share.
(E) In millions, adjusted for stock splits.
(F) Quarters may not add to total due to change in shares outstanding.

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 38.47 | P/E RATIO 19.0 (Trailing: 22.1 / Median: 20.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 2.1% | VALUE LINE 473

TIMELINESS 3 Raised 5/12/06
SAFETY 3 Lowered 1/4/91
TECHNICAL 2 Raised 9/29/06
BETA .85 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	8%
Low	35	(-10%)	Nil

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	3	0	0	0	1	0
Options	1	0	5	1	5	5	2	5	2
to Sell	1	0	5	1	5	6	2	5	2

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	62	69	82
to Sell	53	53	46
Hld's(000)	25543	26475	29035

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	
High:	18.4	19.9	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	38.4							Target Price Range
Low:	13.6	14.9	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0							2009 2010 2011
	25.90	24.99	25.93	25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	*47.15*	*47.90*	Revenues per sh [A]
	3.96	1.53	3.34	3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	*6.05*	*6.05*	"Cash Flow" per sh
	1.81	d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	*1.95*	*2.00*	Earnings per sh [A B]
	1.40	.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	*.82*	*.82*	Div'ds Decl'd per sh [C■]
	5.06	3.76	5.02	5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	*7.40*	*7.45*	Cap'l Spending per sh
	17.63	15.88	15.99	15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	*19.50*	*20.60*	Book Value per sh
	20.04	20.60	20.60	21.00	21.26	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	*42.00*	*43.00*	Common Shs Outst'g [D]
	8.7	--	16.6	26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio
	.65	--	1.01	1.57	.92	NMF	NMF	1.40	.69	1.20	1.04	.97	1.09	1.09	.76	1.10			Relative P/E Ratio
	8.9%	7.0%	5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%			Avg Ann'l Div'd Yield
							644.1	732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	*1980*	*2060*	Revenues ($mill) [A]
							6.6	20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	48.1	*85.0*	*85.0*	Net Profit ($mill)
							37.1%	29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	*34.0%*	*35.0%*	Income Tax Rate
							1.0%	2.8%	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	*4.2%*	*4.2%*	Net Profit Margin
							60.2%	63.6%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	*61.3%*	*60.4%*	Long-Term Debt Ratio
							34.4%	31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	*38.7%*	*39.6%*	Common Equity Ratio
							1104.8	1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1988.6	2076.0	*2120*	*2235*	Total Capital ($mill)
							1278.5	1360.3	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	*2600*	*2750*	Net Plant ($mill)
							2.8%	3.9%	5.8%	4.8%	4.8%	5.1%	4.3%	4.2%	5.0%	4.3%	*6.0%*	*5.5%*	Return on Total Cap'l
							1.5%	4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	*10.5%*	*9.5%*	Return on Shr. Equity
							1.7%	5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	*10.5%*	*9.5%*	Return on Com Equity
							NMF	NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	*6.5%*	*5.5%*	Retained to Com Eq
							NMF	107%	50%	64%	67%	71%	70%	72%	49%	65%	*39%*	*41%*	All Div'ds to Net Prof

LEGENDS
2.10 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH INDEX
1 yr.	44.5	15.5
3 yr.	82.6	49.4
5 yr.	115.3	85.9

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CAPITAL STRUCTURE as of 9/30/06

Total Debt $1393.4 mill. Due in 5 Yrs $379.5 mill.
LT Debt $1366.1 mill. LT Interest $88.0 mill.
(Total interest coverage: 2.1x)

Pension Assets-12/05 $359.6 mill. Oblig. $511.0 mill.

Pfd Stock None

Common Stock 41,464,506 shs. as of 11/2/06

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)

	2004	2005	9/30/06
Cash Assets	13.6	29.6	31.6
Other	418.4	513.1	281.3
Current Assets	432.0	542.7	312.9
Accts Payable	165.9	259.5	102.4
Debt Due	129.8	107.2	27.3
Other	187.3	254.3	202.0
Current Liab.	483.0	621.0	331.7
Fix. Chg. Cov.	166%	167%	197%

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	4.5%	5.0%	3.5%
"Cash Flow"	4.0%	3.5%	3.5%
Earnings	7.5%	-0.5%	9.0%
Dividends	0.5%	--	Nil
Book Value	2.0%	3.0%	4.5%

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	403.3	255.8	220.2	351.7	1231.0
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	361.1	313.3	497.0	1714.3
2006	676.9	430.9	351.8	*520.4*	*1980*
2007	*690*	*450*	*370*	*550*	*2060*

EARNINGS PER SHARE [B]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.76	d.12	d.51	1.00	1.13
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	d.07	d.43	.87	1.25
2006	1.11	.02	d.26	*1.08*	*1.95*
2007	*1.15*	*.05*	*d.30*	*1.10*	*2.00*

QUARTERLY DIVIDENDS PAID [C■]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.205	.205	.205	.205	.82
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approx. 1.7 million customers in sections of Arizona, Nevada, and California. '05 margin mix: resid. and small commercial, 66%; large commercial and industrial, 5%; transportation, 9%. Annual volume: 2.2 billion therms. Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 4,940 employees. Officers & Directors own 2.3% of common stock (3/06 Proxy). Chairman: LeRoy Hanneman. Chief Executive Officer: Jeffrey W. Shaw. Incorporated: California. Address: 5241 Spring Mountain Rd., Las Vegas, Nevada 89193. Telephone: 702-876-7011. Internet: www.swgas.com.

Southwest Gas reported improving results in the third quarter. Revenues came in at $351.8 million, a 12% increase. The company reported a share-net loss of $0.26, compared to a loss of $0.43 in the prior year's period. Due to the seasonal nature of its operations (natural gas sales peak in the winter), losses during the second and third quarters are not uncommon. We find the recent period's improvement encouraging. Rate relief (primarily in Arizona) added roughly $10 million to operating income. Moderating operations and maintenance expenses also benefited the company. Growth in the customer base (discussed below) contributed, as well. For full-year 2006, we look for revenues and share earnings to advance by roughly 15% and 56%, respectively. We have increased our earnings-per-share estimate by a dime, to $1.95, as we expect strong performance during the fourth quarter.

During the past 12 months, the company built its customer base by over 4%. The pace of growth has been impressive in recent times. We expect this pattern to continue. However, as SWX continues to expand, it is likely to incur up-front costs and increased operating expenses. Improvements in technology may offset these costs, somewhat.

We are mildly optimistic about growth prospects for the coming years. We anticipate modest advances in both the top and bottom line figures from 2007 to the end of the decade, as demographic trends favor Arizona and Nevada. The net profit margin should improve, as well. But, in addition to customer growth, continued strength depends upon such variables as favorable weather temperatures and the company's ability to obtain sufficient rate relief. Its increased focus in this area is encouraging.

These shares are not a standout for the coming year. Moreover, appreciation potential is below average for the pull to late decade, as the shares are trading within our projected range. The dividend yield of 2.1% is lower than that of most utility stocks, and income-oriented accounts should note that the company has not increased its payout in roughly a decade. Investors could likely find better choices elsewhere.

Michael F. Napoli *December 15, 2006*

(A) Incl. income for PriMerit Bank on the equity basis through 1994.
(B) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Next egs. report due in March.
(C) Dividends historically paid early March, June, September, December.
■ Div'd reinvest. plan avail.
(D) In millions.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	65

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WGL HOLDINGS NYSE-WGL

RECENT PRICE 33.41 | P/E RATIO 17.4 (Trailing: 19.0 Median: 15.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 4.1% | VALUE LINE 475

TIMELINESS 4 Raised 8/4/06
SAFETY 1 Raised 4/2/93
TECHNICAL 2 Raised 11/17/06
BETA .85 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+5%)	6%
Low	30	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	6	0
to Sell	0	0	0	0	0	0	1	7	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	88	70	73
to Sell	67	77	78
Hld's(000)	27959	27311	29760

	High:	22.4	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.4
	Low:	16.1	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0

LEGENDS
1.00 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 5/95
Options: No
Shaded area indicates recession

Target Price Range 2009 | 2010 | 2011

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.6	15.5
3 yr.	41.1	49.4
5 yr.	50.0	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
18.75	17.50	18.37	21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.94	*55.10*	Revenues per sh A	*60.60*
2.17	2.04	2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.68	*3.85*	"Cash Flow" per sh	*4.45*
1.26	1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.90	*1.90*	Earnings per sh B	*2.35*
1.01	1.05	1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	*1.38*	Div'ds Decl'd per sh C∎	*1.48*
2.38	2.05	2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.40	*3.30*	Cap'l Spending per sh	*3.95*
10.17	9.63	10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	*18.25*	*18.90*	Book Value per sh D	*21.15*
39.23	39.89	40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.86	*49.00*	Common Shs Outst'g E	*49.50*
11.7	12.8	13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.8		Avg Ann'l P/E Ratio	*14.0*
.87	.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.85		Relative P/E Ratio	*.90*
6.9%	7.2%	6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.6%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%		Avg Ann'l Div'd Yield	*4.3%*
969.8	1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2084.2	2089.6	2186.3	2636.7	*2700*	Revenues ($mill) A	*3000*
81.6	82.0	68.6	68.8	84.6	99.9	55.7	112.3	98.0	104.8	87.3	*95.0*	Net Profit ($mill)	*110*
37.7%	36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	*40.0%*	*38.0%*	Income Tax Rate	*38.0%*
8.4%	7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.3%	*3.4%*	Net Profit Margin	*3.8%*
37.6%	41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	*38.0%*	*37.5%*	Long-Term Debt Ratio	*37.0%*
59.4%	56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	*60.0%*	*60.5%*	Common Equity Ratio	*61.0%*
941.1	1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1496.4	*1570*	Total Capital ($mill)	*1760*
1130.6	1217.1	1319.5	1402.7	1460.3	1519.7	1608.8	1874.9	1915.6	1969.7	2057.9	*2270*	Net Plant ($mill)	*2550*
10.1%	9.3%	6.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
13.9%	13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.5%*
14.4%	13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	*9.5%*	*10.0%*	Return on Com Equity	*11.0%*
5.6%	5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	*2.5%*	*2.5%*	Retained to Com Eq	*4.0%*
62%	63%	78%	82%	69%	67%	112%	56%	65%	62%	74%	74%	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $814.5 mill. Due in 5 Yrs $520.0 mill.
LT Debt $576.1 mill. LT Interest $40.0 mill.
(LT interest earned: 4.6x; total interest coverage: 4.2x)
Pension Assets-9/05 $691.7 mill. Oblig. $691.2 mill.
Preferred Stock $28.2 mill. Pfd Div'd $1.3 mill.

Common Stock 48,878,000 shs.

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	6.6	4.8	4.4
Other	426.3	476.2	556.9
Current Assets	432.9	481.0	561.3
Accts Payable	179.0	204.9	208.5
Debt Due	156.3	91.0	238.4
Other	77.6	115.5	113.9
Current Liab.	412.9	411.4	560.8
Fix. Chg. Cov.	449%	460%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	14.5%	*5.5%*
"Cash Flow"	5.0%	6.5%	*2.0%*
Earnings	4.5%	6.0%	*1.5%*
Dividends	1.5%	1.5%	*2.0%*
Book Value	4.0%	3.0%	*3.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	560.0	851.1	373.2	279.9	2064.2
2004	586.3	862.2	356.9	285.2	2089.6
2005	623.4	929.8	349.0	284.1	2186.3
2006	N/A	N/A	N/A	322.5	2636.7
2007	*960*	*1010*	*380*	*350*	*2700*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	1.10	1.61	d.05	d.36	2.30
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.17	d.23	2.11
2006	.93	1.16	d.01	d.18	1.90
2007	*.91*	*1.29*	*d.10*	*d.20*	*1.90*

Calendar	QUARTERLY DIVIDENDS PAID C ∎ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.315	.318	.318	.318	1.27
2002	.316	.32	.32	.32	1.28
2003	.32	.325	.325	.325	1.30
2004	.325	.333	.333	.333	1.32
2005	.333	.338	.338	.338	

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA. and MD. to resident'l and comm'l users (1,092,198 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 9.3% of common stock; Off./dir. less than 1% (1/06 proxy). Chrmn. & CEO: J.H. DeGraffenreidt, Inc.; D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

Fiscal 2006 (ended September 30th) was not the best of years for WGL Holdings. Results were impacted by a decline in natural gas deliveries due to customer conservation, along with higher operation and maintenance expenses, and results that were below last year's level at the company's nonutility segment. For 2007, we look for earnings to remain flat. This includes about $1.60 from the main utility segment, and $0.30 from nonutility operations. The company expects to add 20,000 new customers this year, slightly below previous years' additions. However, indicators point to a rebound in home construction in 2008.

Washington Gas Light aims to improve the consistency of its earnings through new rate designs. In 2006, the company was able to fully neutralize the effect of warmer-than-normal temperatures in the District of Columbia and Virginia. However, in Maryland the company is able to protect against both warmer weather and customer conservation through its revenue normalization adjustment plan. Due to the success of this plan, the company filed in September a similar rate case in Virginia, which also includes a performance-based rate plan that would put new rates in place by February if approved. The company also intends to file a rate case in the spring of 2007 to recover the costs associated with the Prince George's county rehabilitation program. We think the company is likely to receive most, if not all, of these costs.

The company is looking to improve its nonregulated operations. In September, WGL sold its interest in American Combustion Industries, which had been underperforming. This should permit management to focus on growth businesses. The company initiated a partnership with select heating, ventilating, and air conditioning contractors to increase market penetration through residential conversions. WGL expects the conversion rate, which is currently 7%, to increase to 14% for new residential businesses in 2007.

These shares are best suited for conservative investors. The dividend is well covered, and the yield is above its distribution counterparts. But investors should note the limited capital gains prospects.

Evan I. Blatter *December 15, 2006*

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	60

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); discontinued operations: '06, (14¢). Next earnings report due early Feb. (C) Dividends historically paid early February, May, August, and November. ∎ Dividend reinvestment plan available. (D) Includes deferred charges and intangibles. '05: $150.0 million, $3.08/sh. (E) In millions, adjusted for stock split. (F) Quarterly revenues will be adjusted following 10k release.

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		Confirmed By Investor Relations		Not Confirmed	
		Regulated	Non-regulated	Regulated	Non-regulated
Atmos Energy					
Revenues (in thousands)	$ 3,649,851	X	X		
Utility	$ 2,481,856	X			
Marketing	$ 81,857		X		
Pipeline & Storage	$ 1,799				
Non-utility					

Source: Atmos 10-K, period ending 9/30/06, p.117

AGL Resources				X	
Revenues (in millions)					?
Distribution	$ 1,624				?
Retail Energy	$ 930				?
Energy Investments	$ 41				
Wholesale Services	$ 182				

Source: AGL 10-K, period ending 12/31/06, p.93

New Jersey Resources		X			
Revenues (in thousands)			X		
Natural Gas Distribution	$ 1,138,774		X		
Energy Services	$ 2,133,540				
Retail & Other	$ 27,568				

Source: New Jersey Resources 10-K, period ending 9/30/06, pp. 31, 40, 47, 48
Confirmed by Dennis Puma of NJR Investor Relations Department (3/12/07)

NICOR			X		
Revenues (in millions)				X	
Gas Distribution	$ 2,452.3			X	
Shipping	$ 398.3				
Other Energy Services	$ 215.9				

Source: NICOR 10-K, period ending 12/31/06, pp.16,18
Classification of regulated vs. non-regulated categories
provided by Mark Knox, Investor Relations, NICOR

Northwest Natural Gas				X	
Revenues (in thousands)				X	
Utility	$ 1,000,188				
Storage	$ 12,984				

Source: Northwest Natural Gas 10-K, period ending 12/31/06, pp.26, 85

Piedmont Natural Gas			X		
Revenues (in thousands)					
Utility	$ 1,924,628				

Source: Piedmont 10-K, period ending 10/31/06, p.65
Classification of regulated vs. non-regulated categories provided by Margaret Griffith, Investor Relations
provided by Margaret Griffith, Investor Relations, Piedmont. She stipulated that they have
investment stakes in smaller subsidiaries accounted for by the equity method that would be
non-regulated. These are referenced in their 10-K, Footnote 11, page 60.

Southwest Gas				X	X
Revenue (in thousands)					
Natural Gas	$ 1,727,394				
Construction Services	$ 297,364				

Source: Southwest 10-K, period ending 12/31/06, p. 24-25

WGL Holdings				X	
Revenues (in thousands)					
Regulated Utility	$ 1,637,491				
Non-Utility	$ 1,001,596				

Source: WGL Holdings 10-K, period ending 9/30/06, p.49, 52

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

Form 10-K

(Mark One)

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year 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 1-10042

Atmos Energy Corporation

(Exact name of registrant as specified in its charter)

Texas and Virginia	75-1743247
(State or other jurisdiction of incorporation or organization)	*(IRS employer identification no.)*
Three Lincoln Centre, Suite 1800 5430 LBJ Freeway, Dallas, Texas *(Address of principal executive offices)*	75240 *(Zip code)*

Registrant's telephone number, including area code:
(972) 934-9227

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common stock, No Par Value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

The aggregate market value of the voting stock held by non-affiliates of the registrant as of the last business day of the registrant's most recently completed second fiscal quarter, March 31, 2006, was $2,064,662,421.

As of November 8, 2006, the registrant had 81,823,767 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement to be filed for the Annual Meeting of Shareholders on February 7, 2007 are incorporated by reference into Part III of this report.

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GLOSSARY OF KEY TERMS

AEC	Atmos Energy Corporation
AEH	Atmos Energy Holdings, Inc.
AEM	Atmos Energy Marketing, LLC
AES	Atmos Energy Services, LLC
APB	Accounting Principles Board
APS	Atmos Pipeline and Storage, LLC
ATO	Trading symbol for Atmos Energy Corporation common stock on the New York Stock Exchange
Bcf	Billion cubic feet
COSO	Committee of Sponsoring Organizations of the Treadway Commission
EITF	Emerging Issues Task Force
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fitch	Fitch Ratings, Ltd.
FSP	FASB Staff Position
GRIP	Gas Reliability Infrastructure Program
Heritage	Heritage Propane Partners, L.P.
iFERC	Inside FERC
KPSC	Kentucky Public Service Commission
LGS	Louisiana Gas Service Company and LGS Natural Gas Company, which were acquired July 1, 2001
LPSC	Louisiana Public Service Commission
Mcf	Thousand cubic feet
MDWQ	Maximum daily withdrawal quantity
MMcf	Million cubic feet
Moody's	Moody's Investor Services, Inc.
MPSC	Mississippi Public Service Commission
MVG	Mississippi Valley Gas Company, which was acquired December 3, 2002
NYMEX	New York Mercantile Exchange, Inc.
NYSE	New York Stock Exchange
RRC	Railroad Commission of Texas
RSC	Rate Stabilization Clause
S&P	Standard & Poor's Corporation
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
TXU Gas	TXU Gas Company, which was acquired on October 1, 2004
USP	U.S. Propane, L.P.
VCC	Virginia Corporation Commission
WNA	Weather Normalization Adjustment

PART I

The terms "we," "our," "us," "Atmos" and "Atmos Energy" refer to Atmos Energy Corporation and its subsidiaries, unless the context suggests otherwise.

ITEM 1. *Business*

Overview

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the natural gas utility business as well as other natural gas nonutility businesses. We are one of the country's largest natural-gas-only distributors based on number of customers and one of the largest intrastate pipeline operators in Texas based upon miles of pipe. As of September 30, 2006, we distributed natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public authority and industrial customers through our seven regulated utility divisions, which covered service areas in 12 states. Our primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. We have more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we primarily provide natural gas management and marketing services to municipalities, other local gas distribution companies and industrial customers in 22 states and natural gas transportation and storage services to certain of our utility divisions and to third parties.

We were organized under the laws of Texas in 1983 as Energas Company for the purpose of owning and operating the natural gas distribution business of Pioneer Corporation in Texas. In September 1988, we changed our name to Atmos Energy Corporation. As a result of the merger with United Cities Gas Company in July 1997, we also became incorporated in Virginia.

Operating Segments

Our operations are divided into four segments:

- the utility segment, which includes our regulated natural gas distribution and related sales operations,
- the natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- the pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- the other nonutility segment, which includes all of our other nonregulated nonutility operations.

Strategy

Our overall strategy is to:

- deliver superior shareholder value,
- improve the quality and consistency of earnings growth, while operating our natural gas utility and nonutility businesses exceptionally well and
- enhance and strengthen a culture built on our core values.

Over the last five years, we have primarily grown through two significant acquisitions, our acquisition in December 2002 of Mississippi Valley Gas Company (MVG) and our acquisition in October 2004 of the natural gas distribution and pipeline operations of TXU Gas Company (TXU Gas).

We have experienced over 20 consecutive years of increasing dividends and earnings growth after giving effect to our acquisitions. We have achieved this record of growth while operating our utility operations efficiently by managing our operating and maintenance expenses and leveraging our technology, such as our 24-hour call centers, to achieve more efficient operations. In addition, we have focused on regulatory rate

proceedings to increase revenue as our costs increase and mitigated weather-related risks through weather-normalized rates that now apply to most of our service areas. We have also strengthened our nonutility businesses by increasing gross profit margins, actively pursuing opportunities to increase the amount of storage available to us and expanding commercial opportunities in our pipeline and storage segment.

Our core values include focusing on our employees and customers while conducting our business with honesty and integrity. We continue to strengthen our culture through ongoing communications with our employees and enhanced employee training.

Utility Segment Overview

We operated our utility segment through the following seven regulated natural gas utility divisions during the year ended September 30, 2006:

- Atmos Energy Colorado-Kansas Division,
- Atmos Energy Kentucky Division,
- Atmos Energy Louisiana Division,
- Atmos Energy Mid-States Division,
- Atmos Energy Mid-Tex Division,
- Atmos Energy Mississippi Division and
- Atmos Energy West Texas Division.

Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

Our natural gas utility distribution business is seasonal and dependent on weather conditions in our service areas. Gas sales to residential and commercial customers are greater during the winter months than during the remainder of the year. The volumes of gas sales during the winter months will vary with the temperatures during these months.

In addition to weather, our financial results are affected by the cost of natural gas and economic conditions in the areas that we serve. Higher gas costs, which we are generally able to pass through to our customers under purchased gas adjustment clauses, may cause customers to conserve or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt expense and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

The effect of weather that is above or below normal is substantially offset through weather normalization adjustments, known as WNA, which are now approved by the regulators for over 90 percent of residential and commercial meters in our service areas. WNA allows us to increase customers' bills to offset lower gas usage when weather is warmer than normal and decrease customers' bills to offset higher gas usage when weather is colder than normal.

Prior to October 1, 2006, our largest division, the Mid-Tex Division, did not have WNA. However, its operations benefited from a rate structure that combined a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provided for the recovery of most of our fixed costs for such operations under most weather conditions. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal.

In May 2006, the Mid-Tex Division filed a Statement of Intent seeking additional annual revenues of $60 million and several rate design changes including WNA. In July 2006, the Railroad Commission of Texas

(RRC) approved an interim and a permanent WNA, effective October 1, 2006 for the Mid-Tex Division. The agreement provided that the interim WNA will be based on the use of 30 years of weather history, while the permanent WNA will allow the parties to contest the appropriate period of weather data to use in calculating normal weather. The permanent WNA will also be modified or adjusted to conform to the rate design that the RRC ultimately approves in the case. Additionally, in May 2006, we agreed to a settlement with the Louisiana Public Service Commission (LPSC) that authorized the implementation of WNA in our Louisiana Division effective December 1, 2006.

As of September 30, 2006 we had, or received regulatory approvals for WNA for our customer meters in the following service areas for the following periods:

Georgia	October — May
Kansas	October — May
Kentucky	November — April
Louisiana[1]	December — March
Mid-Tex[1]	October — May
Mississippi	November — April
Tennessee	November — April
Amarillo, Texas	October — May
West Texas	October — May
Lubbock, Texas	October — May
Virginia	January — December

[1] Effective beginning with the 2006-2007 winter heating season.

Our natural gas supply comes from a variety of third-party providers and from gas held in storage. We anticipate that the natural gas supply for the upcoming winter heating season will be provided by a variety of suppliers, including independent producers, marketers and pipeline companies, in addition to withdrawals of gas from storage. Additionally, the natural gas supply for our Mid-Tex Division includes peaking and spot purchase agreements. We also contract for storage service in underground storage facilities on many of the interstate pipelines serving us. We estimate the peak-day availability of natural gas supply from long-term contracts, short-term contracts and withdrawals from underground storage to be approximately 4.2 Bcf. The peak-day demand for our utility operations in fiscal 2006 was on December 8, 2005, when sales to customers reached approximately 3.4 Bcf.

Supply arrangements are contracted from our suppliers on a firm basis with various terms at market prices. The firm supply consists of both base load and swing supply quantities. Base load quantities are those that flow at a constant level throughout the month and swing supply quantities provide the flexibility to change daily quantities to match increases or decreases in requirements related to weather conditions. Except for local production purchases, we select suppliers through a competitive bidding process by requesting proposals from suppliers that have demonstrated that they can provide reliable service. We select these suppliers based on their ability to deliver gas supply to our designated firm pipeline receipt points at the lowest cost. Major suppliers during fiscal 2006 were Anadarko Energy Services, BP Energy Company, Chesapeake Energy Marketing, Inc., ConocoPhillips Company, Cross Timbers Energy Services, Inc., Devon Gas Services, L.P., Enbridge Marketing (US) L.P., PPM Energy, Inc., Tenaska Marketing and Atmos Energy Marketing, LLC, our natural gas marketing subsidiary.

The combination of base load, peaking and spot purchase agreements, coupled with the withdrawal of gas held in storage, allows us the flexibility to adjust to changes in weather, which minimizes our need to enter into long-term firm commitments.

Also, to maintain our deliveries to high priority customers, we have the ability, and have exercised our right, to curtail deliveries to certain customers under the terms of interruptible contracts or applicable state statutes or regulations. Our customers' demand on our system is not necessarily indicative of our ability to

meet current or anticipated market demands or immediate delivery requirements because of factors such as the physical limitations of gathering, storage and transmission systems, the duration and severity of cold weather, the availability of gas reserves from our suppliers, the ability to purchase additional supplies on a short-term basis and actions by federal and state regulatory authorities. Curtailment rights provide us the flexibility to meet the human-needs requirements of our customers on a firm basis. Priority allocations imposed by federal and state regulatory agencies, as well as other factors beyond our control, may affect our ability to meet the demands of our customers. We anticipate no problems with obtaining additional gas supply as needed for our customers.

We receive gas deliveries for all of our utility divisions, except for our Mid-Tex Division, through 37 pipeline transportation companies, both interstate and intrastate, to satisfy our natural gas needs. The pipeline transportation agreements are firm and many of them have "pipeline no-notice" storage service which provides for daily balancing between system requirements and nominated flowing supplies. These agreements have been negotiated with the shortest term necessary while still maintaining our right of first refusal. The natural gas supply for our Mid-Tex Division is delivered by our Atmos Pipeline — Texas Division.

The following is a brief description of our seven natural gas utility divisions. Additional information for our natural gas utility divisions is presented under the caption "Operating Statistics".

Atmos Energy Colorado-Kansas Division. Our Colorado-Kansas Division operates in Colorado, Kansas and the southwestern corner of Missouri and is regulated by each respective state's public service commission with respect to accounting, rates and charges, operating matters and the issuance of securities. We operate under terms of non-exclusive franchises granted by the various cities. Rates in our Kansas service area are subject to WNA. The principal transporters of the Colorado-Kansas Division's gas supply requirements are Colorado Interstate Gas Company, Northwest Pipeline, Public Service Company of Colorado and Southern Star Central Pipeline. Additionally, the Colorado-Kansas Division purchases substantial volumes from producers that are connected directly to its distribution system.

Atmos Energy Kentucky Division. Our Kentucky Division operates in Kentucky and is regulated by the Kentucky Public Service Commission (KPSC), which regulates utility services, rates, issuance of securities and other matters. We operate in various incorporated cities pursuant to non-exclusive franchises granted by these cities. The sale of natural gas for use as vehicle fuel in Kentucky is unregulated. In February 2006, the KPSC approved our request to continue the performance-based ratemaking mechanism for an additional five-year period. Under the performance-based mechanism, we and our customers jointly share in any actual gas cost savings achieved when compared to pre-determined benchmarks. Our rates are also subject to WNA. The Kentucky Division's gas supply is delivered primarily by Midwestern Pipeline, Tennessee Gas Pipeline Company, Texas Gas Transmission LLC and Trunkline Gas Company. As noted below, this division was combined with the Mid-States Division effective October 1, 2006.

Atmos Energy Louisiana Division. Our Louisiana Division operates in Louisiana and serves the metropolitan area of Monroe, the suburban areas of New Orleans and western Louisiana. Our Louisiana Division is regulated by the Louisiana Public Service Commission, which regulates utility services, rates and other matters. We operate most of our service areas pursuant to a non-exclusive franchise granted by the governing authority of each area. Direct sales of natural gas to industrial customers in Louisiana, who use gas for fuel or in manufacturing processes, and sales of natural gas for vehicle fuel are exempt from regulation and are recognized in our natural gas marketing segment. Effective beginning with the 2006-2007 winter heating season, rates in our Louisiana service area will be subject to WNA. The principal transporters of the Louisiana Division's gas supply requirements are Acadian Pipeline, Gulf South, Louisiana Intrastate Gas Company, Texas Gas Transmission LLC and Trans Louisiana Gas Pipeline, Inc., a subsidiary of Atmos Pipeline and Storage, LLC.

Atmos Energy Mid-States Division. Our Mid-States Division operates in Georgia, Illinois, Iowa, Missouri, Tennessee and Virginia. In each of these states, our rates, services and operations as a natural gas distribution company are subject to general regulation by each state's public service commission. We operate in each community, where necessary, under a franchise granted by the municipality for a fixed term of years. In Tennessee and Georgia, we have WNA and a performance-based rate program, which provides incentives

for us to find ways to lower costs and share the cost savings with our customers. We have WNA in our Virginia service area that covers the entire year. Our Mid-States Division is served by 13 interstate pipelines; however, the majority of the volumes are transported through Columbia Gulf, East Tennessee Pipeline, Southern Natural Gas and Tennessee Gas Pipeline. The Kentucky Division was combined with the Mid-States Division effective October 1, 2006.

Atmos Energy Mid-Tex Division. Our Mid-Tex Division includes the natural gas distribution operations that operate in the north-central, eastern and western parts of Texas. The Mid-Tex Division purchases, distributes and sells natural gas in approximately 550 cities and towns, including the 11-county Dallas/ Fort Worth metropolitan area. This division currently operates under a system-wide rate structure. The governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The RRC has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality. Effective beginning with the 2006-2007 winter heating season, rates in our Mid-Tex service area will be subject to WNA.

Atmos Energy Mississippi Division. Our Atmos Energy Mississippi Division operates in Mississippi and is regulated by the Mississippi Public Service Commission (MPSC) with respect to rates, services and operations. We operate under non-exclusive franchises granted by the municipalities we serve. Through fiscal 2005, we operated under a rate structure that allowed us, over a five-year period, to recover a portion of our integration costs associated with the MVG acquisition and operations and maintenance costs in excess of an agreed-upon benchmark. In addition, we were required to file for rate adjustments based on our expenses every six months. Effective October 1, 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, beginning October 1, 2005, we moved from a semi-annual filing process to an annual filing process. We also have WNA in Mississippi. This division's gas supply is delivered primarily by Gulf South Pipeline Company, Tennessee Gas Pipeline Company, Southern Natural Gas Company, Texas Eastern Transmission, Texas Gas Transmission LLC, Trunkline Gas Co. LLC and Enbridge Marketing LP.

Atmos Energy West Texas Division. Our West Texas Division operates in Texas in three primary service areas: the Amarillo service area, the Lubbock service area and the West Texas service area. Similar to our Mid-Tex Division, the governing body of each municipality we serve has original jurisdiction over all utility rates, operations and services within its city limits, except with respect to sales of natural gas for vehicle fuel and agricultural use. We operate pursuant to non-exclusive franchises granted by the municipalities we serve, which are subject to renewal from time to time. The RRC has exclusive appellate jurisdiction over all rate and regulatory orders and ordinances of the municipalities and exclusive original jurisdiction over rates and services to customers not located within the limits of a municipality. We have WNA in each of our service areas. Our West Texas Division receives transportation service from ONEOK Pipeline. In addition, the West Texas Division purchases a significant portion of its natural gas supply from Pioneer Natural Resources, which is connected directly to our Amarillo, Texas, distribution system.

Natural Gas Marketing Segment Overview

Our natural gas marketing and other nonutility segments, which are organized under Atmos Energy Holdings, Inc. (AEH), have operations in 22 states. Through September 30, 2003, Atmos Energy Marketing, LLC, together with its wholly-owned subsidiaries Woodward Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc., comprised our natural gas marketing segment. Effective October 1, 2003, our natural gas marketing segment was reorganized. The operations of Atmos Energy Marketing, L.L.C. and Trans Louisiana Industrial Gas Company, Inc. were merged into Woodward Marketing, L.L.C., which was renamed Atmos Energy Marketing, LLC (AEM).

We acquired a 45 percent interest in Woodward Marketing, L.L.C. in July 1997 as a result of the merger of Atmos Energy and United Cities Gas Company, which had acquired that interest in May 1995. In April

2001, we acquired the remaining 55 percent interest that we did not own for 1,423,193 restricted shares of our common stock.

AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas consumers primarily in the southeastern and midwestern states and to our Kentucky, Louisiana and Mid-States divisions. These services primarily consist of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price management through the use of derivative products. We use proprietary and customer-owned transportation and storage assets to provide the various services our customers request. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we participate in natural gas storage transactions in which we seek to capture the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in a gross profit margin. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

AEM's management of natural gas requirements involves the sale of natural gas and the management of storage and transportation supplies under contracts with customers generally having one to two year terms. AEM also sells natural gas to some of its industrial customers on a delivered burner tip basis under contract terms from 30 days to two years. At September 30, 2006, AEM had a total of 679 industrial, 73 municipal and 289 other customers.

Pipeline and Storage Segment Overview

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS). The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division, transports natural gas for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. Parking arrangements provide short-term interruptible storage of gas on our pipeline and lending services provide short-term interruptible loans of natural gas from our pipeline to meet market demands. Both of these services are primarily offered on our Atmos Pipeline — Texas system. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. Nine basins located in Texas are believed to contain a substantial portion of the nation's remaining onshore natural gas reserves. This pipeline system provides access to all of these basins.

APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

In May 2006, APS announced plans to form a joint venture with a local natural gas producer to construct a natural gas gathering system in Eastern Kentucky. Referred to as the Straight Creek Project, the new system is expected to relieve severe gas gathering and transportation constraints that historically have burdened natural gas producers in the area and should improve delivery reliability to natural gas customers. In October 2006, the Federal Energy Regulatory Commission (FERC) issued a declaratory order finding that the Straight Creek Project will be exempt from FERC jurisdiction. The joint venture provides APS the opportunity to apply its expertise to the upstream gathering business.

Other Nonutility Segment Overview

Our other nonutility segment consists primarily of the operations of Atmos Energy Services, LLC (AES), and Atmos Power Systems, Inc. which are wholly-owned by our subsidiary, Atmos Energy Holdings, Inc. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services, which began in April 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices in exchange for revenues that are equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Through January 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of Atmos Energy Holdings, Inc., owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with other utility companies to own a limited partnership interest in Heritage Propane Partners, L.P. (Heritage), a publicly-traded marketer of propane through a nationwide retail distribution network. During fiscal 2004, we sold our interest in USP and Heritage. As a result of these transactions, we no longer have an interest in the propane business.

Operating Statistics

The following tables present certain operating statistics for our utility, natural gas marketing, pipeline and storage and other nonutility segments for each of the five fiscal years from 2002 through 2006.

Utility Sales and Statistical Data

	Year Ended September 30				
	2006	2005[1]	2004	2003[1]	2002
METERS IN SERVICE, end of year					
Residential	2,886,042	2,862,822	1,506,777	1,498,586	1,247,247
Commercial	275,577	274,536	151,381	151,008	122,156
Industrial	2,661	2,715	2,436	3,799	2,118
Agricultural	8,714	9,639	8,397	9,514	10,576
Public authority and other	8,205	8,128	10,145	9,891	7,244
Total meters	3,181,199	3,157,840	1,679,136	1,672,798	1,389,341
HEATING DEGREE DAYS[2]					
Actual (weighted average)	2,527	2,587	3,271	3,473	3,368
Percent of normal	87%	89%	96%	101%	94%
UTILITY SALES VOLUMES — MMcf[3]					
Gas Sales Volumes					
Residential	144,780	162,016	92,208	97,953	77,386
Commercial	87,006	92,401	44,226	45,611	35,796
Industrial	26,161	29,434	22,330	23,738	14,499
Agricultural	5,629	3,348	4,642	7,884	10,988
Public authority and other	8,457	9,084	9,813	9,326	5,875
Total gas sales volumes	272,033	296,283	173,219	184,512	144,544
Utility transportation volumes	126,960	122,098	87,746	70,159	69,589
Total utility throughput	398,993	418,381	260,965	254,671	214,133
UTILITY OPERATING REVENUES (000's)[3]					
Gas Sales Revenues					
Residential	$2,068,736	$1,791,172	$ 923,773	$ 873,375	$ 535,981
Commercial	1,061,783	869,722	400,704	367,961	221,728
Industrial	276,186	229,649	155,336	151,969	70,164
Agricultural	40,664	27,889	31,851	48,625	37,951
Public authority and other	103,936	86,853	77,178	65,921	31,731
Total utility gas sales revenues	3,551,305	3,005,285	1,588,842	1,507,851	897,555
Transportation revenues	62,215	59,996	31,714	30,461	28,786
Other gas revenues	37,071	37,859	17,172	15,770	11,185
Total utility operating revenues	$3,650,591	$3,103,140	$1,637,728	$1,554,082	$ 937,526
Utility average transportation revenue per Mcf	$ 0.49	$ 0.49	$ 0.36	$ 0.43	$ 0.41
Utility average cost of gas per Mcf sold	$ 10.02	$ 7.41	$ 6.55	$ 5.76	$ 3.87
Employees	4,402	4,327	2,742	2,817	2,255

See footnotes following these tables.

Utility Sales and Statistical Data By Division

	Year Ended September 30, 2006								
	Colorado-Kansas	Kentucky	Louisiana	Mid-States	West Texas	Mississippi	Mid-Tex	Other[4]	Total Utility
METERS IN SERVICE									
Residential	213,566	158,408	330,694	277,998	273,520	241,406	1,390,450	—	2,886,042
Commercial	21,440	18,228	23,108	36,686	25,984	27,868	122,263	—	275,577
Industrial	84	240	—	681	808	643	205	—	2,661
Agricultural	312	—	—	—	8,402	—	—	—	8,714
Public authority and other	543	1,637	—	1,034	2,166	2,825	—	—	8,205
Total	235,945	178,513	353,802	316,399	310,880	272,742	1,512,918	—	3,181,199
HEATING DEGREE DAYS[2]									
Actual	5,466	4,349	1,319	3,515	3,561	2,757	1,697	—	2,527
Percent of normal	99%	100%	78%	95%	100%	102%	72%	—	87%
SALES VOLUMES — MMcf[3]									
Gas Sales Volumes									
Residential	15,113	9,249	12,131	15,065	15,609	12,601	65,012	—	144,780
Commercial	5,901	4,526	6,944	11,328	6,309	6,440	45,558	—	87,006
Industrial	419	1,830	—	6,945	3,933	8,250	4,784	—	26,161
Agricultural	619	—	—	—	5,010	—	—	—	5,629
Public authority and other	1,390	1,237	—	226	1,962	3,642	—	—	8,457
Total	23,442	16,842	19,075	33,564	32,823	30,933	115,354	—	272,033
Transportation Volumes	9,680	25,871	6,310	20,654	15,135	1,702	47,608	—	126,960
Total Throughput	33,122	42,713	25,385	54,218	47,958	32,635	162,962	—	398,993
OPERATING MARGIN (000's)[3]	$ 71,000	$ 50,271	$ 98,502	$106,742	$ 93,693	$ 92,515	$ 412,334	$ —	$ 925,057
OPERATING EXPENSES (000's)[3]									
Operation and maintenance	$ 28,235	$ 19,874	$ 40,741	$ 38,148	$ 33,332	$ 44,533	$ 154,412	$ (1,756)	$ 357,519
Depreciation and amortization	$ 13,578	$ 11,636	$ 21,201	$ 22,172	$ 13,690	$ 10,596	$ 74,375	$ (2,755)	$ 164,493
Taxes, other than income	$ 6,663	$ 4,423	$ 8,788	$ 10,867	$ 21,509	$ 14,110	$ 111,844	$ —	$ 178,204
Impairment of long-lived assets	$ —	$ —	$ —	$ —	$ 22,947	$ —	$ —	$ —	$ 22,947
OPERATING INCOME (000's)[3]	$ 22,524	$ 14,338	$ 27,772	$ 35,555	$ 2,215	$ 23,276	$ 71,703	$ 4,511	$ 201,894
CAPITAL EXPENDITURES (000's)	$ 19,466	$ 16,645	$ 32,218	$ 38,307	$ 27,374	$ 15,389	$ 134,762	$ 23,581	$ 307,742
PROPERTY, PLANT AND EQUIPMENT, NET (000's)	$252,584	$190,959	$328,310	$436,916	$253,086	$226,690	$1,262,516	$132,240	$3,083,301
OTHER STATISTICS, at year end									
Miles of pipe	6,601	3,937	8,214	8,015	14,831	6,415	27,856	—	75,869
Employees	263	220	412	416	341	437	1,458	855	4,402

See footnotes following these tables.

	Year Ended September 30, 2005								
	Colorado-Kansas	Kentucky	Louisiana	Mid-States	West Texas	Mississippi	Mid-Tex	Other[4]	Total Utility
METERS IN SERVICE									
Residential	209,321	159,216	348,576	276,667	267,278	244,136	1,357,628	—	2,862,822
Commercial	20,914	18,350	23,850	36,519	25,410	28,350	121,143	—	274,536
Industrial	81	239	—	684	816	664	231	—	2,715
Agricultural	279	—	—	—	9,360	—	—	—	9,639
Public authority and other	476	1,650	—	1,066	2,139	2,797	—	—	8,128
Total	231,071	179,455	372,426	314,936	305,003	275,947	1,479,002	—	3,157,840
HEATING DEGREE DAYS[2]									
Actual	5,437	4,241	1,301	3,510	3,536	2,583	1,904	—	2,587
Percent of normal	99%	98%	78%	93%	99%	96%	80%	—	89%
SALES VOLUMES — MMcf[3]									
Gas Sales Volumes									
Residential	16,404	10,741	13,134	16,222	19,292	12,985	73,238	—	162,016
Commercial	5,929	4,891	6,811	11,806	7,493	6,711	48,760	—	92,401
Industrial	338	1,858	—	8,205	4,477	9,057	5,499	—	29,434
Agricultural	246	—	—	—	3,102	—	—	—	3,348
Public authority and other	1,355	1,396	—	241	2,296	3,796	—	—	9,084
Total	24,272	18,886	19,945	36,474	36,660	32,549	127,497	—	296,283
Transportation Volumes	8,388	26,066	7,046	20,142	12,390	1,309	46,757	—	122,098
Total Throughput	32,660	44,952	26,991	56,616	49,050	33,858	174,254	—	418,381
OPERATING MARGIN (000's)[3]	$ 70,542	$ 52,302	$ 94,350	$110,012	$ 90,316	$ 91,610	$ 398,234	$ —	$ 907,366
OPERATING EXPENSES (000's)[3]									
Operation and maintenance	$ 26,679	$ 18,618	$ 37,994	$ 38,427	$ 29,701	$ 49,241	$ 146,449	$ (515)	$ 346,594
Depreciation and amortization	$ 13,693	$ 11,739	$ 21,911	$ 23,615	$ 13,249	$ 10,830	$ 64,460	$ —	$ 159,497
Taxes, other than income	$ 5,013	$ 3,288	$ 9,626	$ 12,283	$ 19,846	$ 12,494	$ 102,360	$ —	$ 164,910
OPERATING INCOME (000's)[3]	$ 25,157	$ 18,657	$ 24,819	$ 35,687	$ 27,520	$ 19,045	$ 84,965	$ 515	$ 236,365
CAPITAL EXPENDITURES (000's)	$ 20,690	$ 17,525	$ 31,198	$ 34,176	$ 29,066	$ 15,925	$ 115,024	$ 36,970	$ 300,574
PROPERTY, PLANT AND EQUIPMENT, NET (000's)	$244,250	$183,931	$318,869	$416,825	$263,285	$206,511	$1,167,425	$125,000	$2,926,096
OTHER STATISTICS, at year end									
Miles of pipe	6,530	3,908	8,151	7,958	15,000	6,356	33,701	—	81,604
Employees	267	236	421	412	346	467	1,398	780	4,327

See footnotes following these tables.

Natural Gas Marketing, Pipeline and Storage and Other Nonutility Operations Sales and Statistical Data

	Year Ended September 30				
	2006	2005	2004	2003	2002
CUSTOMERS, end of year					
Industrial	746	624	638	644	641
Municipal	73	69	80	94	101
Other	467	401	237	202	117
Total	1,286	1,094	955	940	859
NATURAL GAS MARKETING SALES VOLUMES — MMcf[3]	336,516	273,201	265,090	294,785	273,692
PIPELINE TRANSPORTATION VOLUMES — MMcf[3]	590,985	563,949	9,395	11,648	12,788
OPERATING REVENUES (000's)[3]					
Natural gas marketing	$3,156,524	$2,106,278	$1,618,602	$1,668,493	$1,031,874
Pipeline and storage	160,567	153,289	19,758	20,298	18,720
Other nonutility	5,898	5,302	3,393	2,853	5,985
Total operating revenues	$3,322,989	$2,264,869	$1,641,753	$1,691,644	$1,056,579
Employees, at year end	230	216	122	88	83

Notes to preceding tables:

(1) The operational and statistical information includes the operations of the Mississippi Division since the December 3, 2002 acquisition date and the Mid-Tex and Atmos Pipeline — Texas Divisions since the October 1, 2004 acquisition date.

(2) A heating degree day is equivalent to each degree that the average of the high and the low temperatures for a day is below 65 degrees. The colder the climate, the greater the number of heating degree days. Heating degree days are used in the natural gas industry to measure the relative coldness of weather and to compare relative temperatures between one geographic area and another. Normal degree days are based on 30-year average National Weather Service data for selected locations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

(3) Sales volumes, revenues, operating margins, operating expense and operating income reflect segment operations, including intercompany sales and transportation amounts.

(4) The Other column represents our utility shared services unit, which provides administrative and other support to our seven regulated utility divisions. Certain costs incurred by this unit are not allocated to our utility divisions.

Ratemaking Activity

Overview

The method of determining regulated rates varies among the states in which our natural gas utility divisions operate. The regulators have the responsibility of ensuring that utilities under their jurisdictions operate in the best interests of customers while providing utility companies the opportunity to earn a reasonable return on investment. Generally, each regulatory authority reviews our rate request and establishes a rate structure intended to generate revenue sufficient to cover our costs of doing business and provide a reasonable return on invested capital.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to

address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments because they provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit (which is defined as operating revenues less purchased gas cost) is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. Additionally, some jurisdictions have introduced performance-based ratemaking adjustments to provide incentives to natural gas utilities to minimize purchased gas costs through improved storage management and use of financial hedges to lock in gas costs. Under the performance-based ratemaking adjustment, purchased gas costs savings are shared between the utility and its customers.

The following table summarizes some information regarding our ratemaking jurisdictions. This information is for regulatory purposes only and may not be representative of our actual financial position.

Jurisdictional Rate Summary

Division	Jurisdiction	Effective Date of Last Rate Action	Rate Base (thousands)[1]	Authorized Rate of Return[1]	Authorized Return on Equity[1]
Atmos Pipeline — Texas	Texas	5/24/04	$417,111	8.258%	10.00%
Colorado-Kansas	Colorado	7/1/05	84,711	8.95%	11.25%
	Kansas	3/1/04	(2)	(2)	(2)
Kentucky	Kentucky	12/21/99	(2)	(2)	(2)
Louisiana	Trans LA	10/1/04	81,645	9.14%	10.50% - 11.50%
	LGS	10/1/04	170,358	9.23%	10.88% - 11.50%
Mid-States	Georgia	12/20/05	62,380	7.57%	10.13%
	Illinois	11/1/00	24,564	9.18%	11.56%
	Iowa	3/1/01	5,000	(2)	11.00%
	Missouri	10/14/95	(2)	10.58%	12.15%
	Tennessee	11/15/95	111,970	(2)	(2)
	Virginia	8/1/04	30,672	8.46% - 8.96%	9.50% - 10.50%
Mid-Tex	Texas	5/24/04	769,721	8.258%	10.00%
Mississippi	Mississippi	1/1/05	196,801	8.23%	9.80%
West Texas	Amarillo	9/1/03	36,844	9.88%	12.00%
	Lubbock	3/1/04	43,300	9.15%	11.25%
	West Texas	5/1/04	87,500	8.77%	10.50%

See footnotes on the following page.

Division	Jurisdiction	Effective Date of Last Rate Action	Authorized Debt/ Equity Ratio	Bad Debt Rider[5]	WNA	Performance-Based Rate Program[3]
Atmos Pipeline — Texas	Texas	5/24/04	50/50	No	N/A	N/A
Colorado-Kansas	Colorado	7/1/05	52/48	No	No	No
	Kansas	3/1/04	(2)	Yes	Yes	No
Kentucky	Kentucky	12/21/99	(2)	No	Yes	Yes
Louisiana	Trans LA	10/1/04	50/50	No	(4)	No
	LGS	10/1/04	53/47	No	(4)	No
Mid-States	Georgia	12/20/05	55/45	No	Yes	Yes
	Illinois	11/1/00	67/33	No	No	No
	Iowa	3/1/01	57/43	No	No	No
	Missouri	10/14/95	(2)	No	No	No
	Tennessee	11/15/95	56/44	No	Yes	Yes
	Virginia	8/1/04	52/48	Yes	Yes	No
Mid-Tex	Texas	5/24/04	50/50	No	(4)	No
Mississippi	Mississippi	1/1/05	47/53	No	Yes	No
West Texas	Amarillo	9/1/03	50/50	Yes	Yes	No
	Lubbock	3/1/04	50/50	No	Yes	No
	West Texas	5/1/04	50/50	No	Yes	No

(1) The rate base and authorized rate of return presented in this table are the rate base and rate of return from the last base rate case for each jurisdiction. These rate bases and rates of return are not necessarily indicative of current or future rate bases or rates of return.

(2) A rate base, rate of return, return on equity or debt/equity ratio was not included in the respective state commission's final decision.

(3) The performance-based rate program provides incentives to natural gas utilities to minimize purchased gas costs by allowing the utility and its customers to share the purchased gas cost savings.

(4) During 2006, our Louisiana and Mid-Tex Divisions received authorization to implement WNA beginning in the 2006-2007 winter heating season.

(5) The bad debt rider allows us to recover from ratepayers the gas cost portion of uncollectible accounts.

Recent Ratemaking Activity

Our current rate strategy focuses on seeking rate designs that reduce or eliminate regulatory lag and separate the recovery of our approved margins from customer usage patterns due to weather-related variability, declining use per customer and energy conservation, also known as decoupling. Additionally, we are seeking to stratify rates for low income households and to recover the gas cost portion of our bad debt expense.

Improving rate design is a long-term process. In the interim, we are addressing regulatory lag issues by directing discretionary capital spending to jurisdictions that permit us to recover our investment in a timely manner and filing rate cases on a more frequent basis to minimize the regulatory lag to keep our actual returns more closely aligned with our allowed returns.

Approximately 97 percent of our utility revenues in the fiscal years ended September 30, 2006, 2005 and 2004 were derived from sales at rates set by or subject to approval by local or state authorities. Net annual revenue increases resulting from ratemaking activity totaling $39.0 million, $6.3 million and $16.2 million became effective in fiscal 2006, 2005 and 2004 as summarized below:

Division	Most Recent Effective Date	Most Recent Rate Action	Jurisdiction	Increase (Decrease) to Revenue for the Year Ended September 30		
				2006	2005	2004
				(In thousands)		
Atmos Pipeline — Texas	8/1/06	GRIP[1]	Texas	$ 5,205	$1,802	$ —
Colorado-Kansas	4/1/04	Show Cause	Colorado	—	—	(1,900)
	1/1/06	Ad Valorem Tax	Kansas	1,565	—	—
	3/1/04	Rate Case	Kansas	—	—	2,500
Louisiana	2/1/06	Stable Rate Filing[2]	LGS	3,326	—	—
	10/1/04	Stable Rate Filing[2]	LGS	—	225	—
Mid-States	8/1/04	Rate Case	Virginia	—	—	372
	12/20/05	Rate Case	Georgia	409	—	—
Mid-Tex	2/1/06	GRIP[1]	Texas	25,313	—	—
Mississippi	(3)	Stable Rate Filing[2]	Mississippi	—	4,300	10,545
	11/1/05	Rate Restructuring	Mississippi	(600)	—	—
West Texas	12/1/05	GRIP[1]	Lubbock	1,263	—	—
	3/1/04	Rate Case	Lubbock	—	—	1,525
	3/1/06	GRIP[1]	West Texas	2,539	—	—
	5/1/04	Rate Case	West Texas	—	—	3,200
				$39,020	$6,327	$16,242

(1) In 2003, the Texas Legislature approved the Gas Reliability Infrastructure Program (GRIP) which allows natural gas utilities the opportunity to include in their rate base annually approved capital costs incurred in the prior calendar year. Natural gas utilities that enter the program will be required to file a complete rate case at least once every five years.

(2) A stable rate filing is a regulatory mechanism designed to allow us to refresh our rates on a periodic basis without filing a formal rate case.

(3) The MPSC had formerly required that we file for rate adjustments every six months. Through May 2005, rate filings were made in May and November of each year and the rate adjustments typically became effective in June and December. See further discussion under the recent ratemaking activity for our Atmos Energy Mississippi Division below.

Additionally, the following ratemaking efforts were initiated during fiscal 2006 but had not been completed as of September 30, 2006:

Division	Rate Action	Jurisdiction	Revenue Requested
			(In thousands)
Louisiana	Stable Rate Filing[1]	LGS	$10,753
Mid-States	Rate Case	Missouri	3,396
	Rate Proceeding[2]	Tennessee	3,400
Mid-Tex	System-wide Case	Texas	60,844
			$78,393

(1) The Louisiana Division has included the Rate Stabilization Clause increase in rates. The increase is subject to refund, pending final resolution of the Stable Rate Filing.

(2) The Tennessee rate proceeding was settled in October 2006. See below for information regarding the settlement.

December 31, 2006, for the test period ending September 30, 2006, with an effective rate adjustment of April 1, 2007. WNA for both service areas will be in effect for an initial three-year period beginning with the winter of 2006-2007. In the third quarter of fiscal 2006, $6.2 million in deferred revenue associated with the 2003 RSC rate adjustment was recognized.

On August 29, 2005, Hurricane Katrina struck the Gulf Coast, inflicting significant damage to our eastern Louisiana operations. The hardest hit areas in our service territory were in Jefferson, St. Tammany, St. Bernard and Plaquemines parishes. Although service has been restored for many of our customers, a significant number of customers will not require gas service for some time, if ever, because of sustained damages. We began implementing new rates, subject to refund, in September 2006 that reflected the reduction of approximately 26,500 customers and included a request to recover costs attributable to Hurricane Katrina. We cannot accurately determine what regulatory actions, if any, may be taken by the regulators with respect to this filing or our ability to fully recover all costs incurred as a result of the storm.

During the second quarter of 2005, the Louisiana Division implemented a rate increase of $3.3 million in its LGS service area. This increase resulted from our RSC filing in 2004 and was subject to refund, pending the final resolution of that filing. As the rate increase was subject to refund, we did not recognize the effects of this increase in our results of operations during fiscal 2005 or the first three quarters of fiscal 2006.

During fiscal 2004, the Louisiana Public Service Commission approved tariff revisions for our LGS service area totaling $0.2 million that became effective in October 2004.

In October 2002, Atmos received written notification from the Executive Secretary of the LPSC asserting that a monthly facilities fee of approximately $0.6 million charged since July 2001 to Atmos by Trans Louisiana Gas Pipeline, Inc., a wholly-owned subsidiary of Atmos, pursuant to a contract between the parties, was excessive. The Executive Secretary asserted that all monthly facilities fees in excess of approximately $0.1 million from July 2001 should be refunded to ratepayers with interest. In October 2003, the LPSC unanimously voted to approve an agreement to allow us to charge a facilities fee of approximately $0.5 million per month (subject to future escalation) beginning November 2003 for a period of 14 years. No retroactive adjustments were required under this agreement.

Atmos Energy Mid-States Division. In April 2006, Atmos filed a rate case in its Missouri service area seeking a rate increase of $3.4 million. The Company is proposing to consolidate the rates for its Missouri properties into three sets of regional rates and consolidate the current purchased gas adjustment (PGA) into one statewide PGA. The Company is also proposing a WNA mechanism. An evidentiary hearing is scheduled to begin on November 27, 2006, with an order expected to be issued in February 2007.

In March 2006, we received notification from the Tennessee Regulatory Authority (TRA) that it disagreed with the way we calculated amounts under its performance-based rate mechanism, which resulted in a one-time $3.3 million income reduction during the second quarter of fiscal 2006. We believe the original calculations were correct and have appealed the TRA's decision.

During the third quarter of fiscal 2005, Atmos filed a rate case in its Georgia service area seeking a rate increase of $4.0 million. In December 2005, the Georgia Public Service Commission (GPSC) approved a $0.4 million increase. In January 2006, we filed an appeal of the GPSC's decision in the Superior Court of Fulton County. Oral arguments were held on September 7, 2006 before the Fulton County Superior Court. The court affirmed the commission's order. We are considering further appeal.

In November 2005, we received a notice from the TRA that it was opening an investigation into allegations by the Consumer Advocate and Protection Division of the Tennessee Attorney General's Office that we were overcharging customers in parts of Tennessee by approximately $10 million per year. We responded to numerous data requests from the TRA Staff. In April 2006, the TRA Staff filed a Report and Recommendation in which it recommended that the TRA convene a contested case procedure for the purpose of establishing a fair and reasonable return. The TRA convened to consider the Staff's recommendation on May 15, 2006 and set a procedural schedule. A hearing was held from August 29, 2006 through August 31, 2006. Of the $10 million rate reduction requested by the Consumer Advocate and Protection Division, the TRA approved on October 27, 2006 a $6.1 million reduction to future rates.

In February 2004, the Mid-States Division filed a rate case with the Virginia Corporation Commission (VCC) to request a $1.0 million increase in our base rates, WNA and recovery of the gas cost component of bad debt expense. The VCC granted a rate increase in November 2004 of $0.4 million that was retroactively effective to July 27, 2004. Additionally, the VCC authorized WNA beginning in July 2005 and the ability to recover the gas cost component of bad debt expense.

Atmos Energy Mid-Tex Division. The following is a discussion of our recent ratemaking activity for our Mid-Tex Division.

Rate Case

During fiscal 2006, we received "show cause" resolutions from approximately 80 cities served by our Mid-Tex Division, including the City of Dallas, which require us to demonstrate that existing distribution rates in the Mid-Tex Division are just and reasonable. In May 2006, in response to these resolutions, we filed a Statement of Intent to increase rates on a division-wide basis. By agreement with the cities, the "show cause" resolutions were consolidated and became part of the Mid-Tex Division's first rate case before the RRC since we acquired the TXU Gas operations in October 2004. In this rate proceeding, we are seeking incremental annual revenues in the Mid-Tex Division of approximately $60 million and several rate design changes, including WNA, revenue stabilization and recovery of the gas cost component of bad debt expense.

In exchange for an agreement to provide the intervening parties in the proceeding additional time to prepare for the hearing, we obtained agreement from the intervenors to implement WNA in the rates for the Mid-Tex Division for the 2006-2007 winter season, which has been approved by the RRC, and to implement WNA in the final rates in this proceeding. The hearing in this proceeding was concluded on November 17, 2006, and a decision is due from the RRC no later than April 2007. During the hearing, the principal issues raised by the cities included the Mid-Tex Division's rate of return, the reduction of rate base for the accumulated deferred federal income taxes and investment tax credits associated with the TXU Gas operations prior to our acquisition, the methodology used by us to allocate certain shared services expenses to the division, and the inclusion of certain items in operation and maintenance expenses.

In addition, under applicable statutes, the RRC is reviewing the interim rate adjustments that were previously granted in response to the Mid-Tex Division's prior GRIP filings and our acquisition of the TXU Gas operations for consistency with the public interest. Any increase that the RRC may grant in this case would be effective prospectively from the date of the final order. However, any decrease that may be ordered by the RRC would be effective from May 31, 2006 pursuant to the agreement with the intervenors for consolidation of the show cause resolutions and the Statement of Intent filing. Any disallowance related to the previously granted GRIP interim rate adjustments would be refunded to customers with interest beginning some time after the issuance of a final order in this proceeding.

While the decision of the RRC in this case cannot be predicted with certainty, we believe that we have adequately demonstrated to the RRC that the Mid-Tex Division is entitled to receive an increase in annual revenues and that the remaining rate design changes should be implemented.

GRIP Filings

In March 2006, the Mid-Tex Division made a GRIP filing to include in rate base approximately $62.2 million of distribution capital expenditures incurred during calendar year 2005, which we estimate would result in additional annual revenues of approximately $11.9 million. The RRC approved this filing in August 2006, and the new customer charges were implemented in September 2006 billings to customers.

In September 2005, the Mid-Tex Division made a GRIP filing to include in rate base approximately $29.4 million of distribution capital expenditures incurred during calendar year 2004, which currently provides additional annual revenues of approximately $6.7 million. The RRC approved this filing in January 2006, and these new charges were included in the monthly customer charge beginning in February 2006.

In December 2004, the Mid-Tex Division made a GRIP filing to include in rate base approximately $32.0 million of distribution capital expenditures made by TXU Gas during calendar year 2003, which

currently provides additional annual revenues of approximately $6.7 million. New monthly customer charges were implemented in October 2005.

Other Regulatory Matters

In September 2006, the Mid-Tex Division filed its annual gas cost reconciliation with the RRC. The filing reflects approximately $24 million in refunds of amounts that were overcollected from customers between July 2005 and June 2006. The Mid-Tex Division has requested and received approval to refund these amounts over a six-month period beginning in November 2006.

In September 2004, the Mid-Tex Division filed its 36-Month Gas Contract Review with the RRC. This proceeding involves a review for reasonableness of gas purchases totaling $2.2 billion made by the Mid-Tex Division from November 2000 through October 2003. A hearing on this matter was held before the RRC in June 2005. The parties negotiated a unanimous settlement agreement providing for a refund of $8 million to customers over a three-year period and for reimbursement of parties' expenses without recovery from customers. The RRC approved the settlement on September 12, 2006. Refunds to customers began in the first quarter of fiscal year 2007.

The Mid-Tex Division is also pursuing an appeal to the Travis County District Court of the Final Order in its last system-wide rate case completed in May 2004 to obtain a return of and on its investment associated with the Poly I replacement pipe that was originally disallowed in its rate case completed in May 2004. The case was argued before the Travis County District Court in July 2006. The Court ruled to uphold the Commission's final order. Steps are being taken to perfect an appeal to the Court of Appeals in Travis County.

Atmos Energy Mississippi Division. Through the first quarter of fiscal 2005, the MPSC required that we file for rate adjustments every six months. Rate filings were made in May and November of each year and the rate adjustments typically became effective in the following July and January.

During the second quarter of fiscal 2005, we agreed with the MPSC to suspend our May 2005 semi-annual filing to allow sufficient time for us and the MPSC to undertake a comprehensive review in an effort to improve our rate design and the ratemaking process. Effective October 2005, our rate design was modified to substitute the original agreed-upon benchmark with a sharing mechanism to allow the sharing of cost savings above an allowed return on equity level. Further, we moved from a semi-annual filing process to an annual filing process. Additionally, our WNA period begins on November 1 instead of November 15, and ends on April 30 instead of May 15. Also, we now have a fixed monthly customer base charge which makes a portion of our earnings less susceptible to usage. As part of the rate design restructuring, we agreed to reduce our rates by approximately $0.6 million. We made our first annual filing under this new structure in September 2006 requesting no change in rates.

In September 2004, the MPSC originally disallowed certain deferred costs totaling $2.8 million. In connection with the modification of our rate design described above, the MPSC decided to allow these costs, and we included these costs in our rates in October 2005.

In June 2006, the MPSC approved a pilot program whereby Trans Louisiana Gas Pipeline (TLGP) will provide asset management services to the Mississippi Division. The asset management program allows TLGP to market certain off-peak gas supply assets, such as company-owned or leased storage and pipeline capacity, on a recallable basis. In return, TLGP will share net positive benefits of the asset management program with Mississippi ratepayers. The pilot program runs from June 1, 2006 to April 30, 2007 and may be extended by the MPSC upon application by Atmos.

In October 2003, the MPSC issued a final order that denied our May 2003 request for a rate increase of $5.8 million. In January 2004, the MPSC authorized additional annual revenue of $5.9 million on our November 2003 filing, which became effective in December 2003. In September 2004, the MPSC authorized additional annualized revenue of $4.7 million on our May 2004 filing, which became effective in June 2004.

We filed our second semiannual filing for 2004 in November 2004, requesting rate adjustments of $6.0 million in annualized revenue. The MPSC allowed us to include $3.0 million in annualized revenue in

our rates effective January 2005. In February 2005, we entered into an agreement with the Mississippi Public Utilities Staff that provides for an additional $1.3 million in annualized revenue that was retroactive to January 2005, which was approved by the MPSC during the second quarter of fiscal 2005.

Atmos Energy West Texas Division. In September 2005, the West Texas Division made a GRIP filing to include in rate base approximately $22.6 million of distribution capital costs incurred during calendar year 2004, which should result in additional annual revenues of approximately $3.8 million. Of this amount, approximately $1.3 million related to our Lubbock jurisdiction and the remaining $2.5 million related to our West Texas jurisdiction. New charges for the filings were included in the monthly customer charge beginning May 2006. Atmos made its 2005 GRIP filings for the West Texas Division and the Lubbock Division in September 2006 requesting no change in rates.

In January 2006, the Lubbock, Texas City Council passed a resolution requiring Atmos to submit copies of all documentation necessary for the city to review the rates of Atmos' West Texas Division to ensure they are just and reasonable. The requested information was provided to the city on February 28, 2006. We believe that we will be able to ultimately demonstrate to the City of Lubbock that our rates are just and reasonable.

In May 2006, Atmos began receiving "show cause" ordinances from several of the cities in the West Texas Division. We made a filing in response to the ordinances on October 2, 2006. We believe that we will be able to ultimately demonstrate to the West Texas cities that our rates are just and reasonable.

In October 2003, our West Texas Division filed a rate case in Lubbock requesting a $3.0 million increase in annual revenues and WNA for our residential, commercial and public-authority customers. The City of Lubbock approved a $1.5 million increase effective March 2004, as well as the proposed WNA.

In September 2003, our West Texas Division filed a rate case in its West Texas System to request a $7.7 million increase in annual revenues and WNA for its residential, commercial and public-authority customers. In May 2004, the 66 cities in its West Texas System approved an increase of $3.2 million in our annual utility revenues. The cities also approved a WNA rider for residential, commercial, public-authority and state-institution customers. This rider became effective in October 2004.

Other Regulation

Each of our utility divisions is regulated by various state or local public utility authorities. We are also subject to regulation by the United States Department of Transportation with respect to safety requirements in the operation and maintenance of our gas distribution facilities. Our distribution operations are also subject to various state and federal laws regulating environmental matters. From time to time we receive inquiries regarding various environmental matters. We believe that our properties and operations substantially comply with and are operated in substantial conformity with applicable safety and environmental statutes and regulations. There are no administrative or judicial proceedings arising under environmental quality statutes pending or known to be contemplated by governmental agencies which would have a material adverse effect on us or our operations. Our environmental claims have arisen primarily from former manufactured gas plant sites in Tennessee, Iowa and Missouri. These claims are fully described in Note 13 to the consolidated financial statements.

FERC allows, pursuant to Section 311 of the Natural Gas Policy Act, gas transportation services through our Atmos Pipeline — Texas assets "on behalf of" interstate pipelines or local distribution companies served by interstate pipelines, without subjecting these assets to the jurisdiction of the FERC.

Competition

Although our utility operations are not currently in significant direct competition with any other distributors of natural gas to residential and commercial customers within our service areas, we do compete with other natural gas suppliers and suppliers of alternative fuels for sales to industrial and agricultural customers. We compete in all aspects of our business with alternative energy sources, including, in particular, electricity. Electric utilities offer electricity as a rival energy source and compete for the space heating, water heating and cooking markets. Promotional incentives, improved equipment efficiencies and promotional rates all contribute to the acceptability of electrical equipment. The principal means to compete against alternative fuels is lower prices,

and natural gas historically has maintained its price advantage in the residential, commercial and industrial markets. However, higher gas prices, coupled with the electric utilities' marketing efforts, have increased competition for residential and commercial customers. In addition, our Natural Gas Marketing segment competes with other natural gas brokers in obtaining natural gas supplies for our customers.

Employees

At September 30, 2006, we had 4,632 employees, consisting of 4,402 employees in our utility segment and 230 employees in our other segments. See "Operating Statistics — Utility Sales and Statistical Data by Division" for the number of employees by division.

Available Information

Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other reports, and amendments to those reports, that we file with or furnish to the Securities and Exchange Commission (SEC) are available free of charge at our website, *www.atmosenergy.com*, as soon as reasonably practicable, after we electronically file these reports with, or furnish these reports to, the SEC. We will also provide copies of these reports free of charge upon request to Shareholder Relations at the address appearing below:

Shareholder Relations
Atmos Energy Corporation
P.O. Box 650205
Dallas, Texas 75265-0205
972-855-3729

Corporate Governance

In accordance with and pursuant to relevant provisions of the Sarbanes-Oxley Act of 2002, related rules and regulations of the Securities and Exchange Commission as well as corporate governance-related listing standards of the New York Stock Exchange, the Board of Directors of the Company has adopted the Company's Corporate Governance Guidelines and revised the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company. In addition, the Board of Directors has updated the charters for each of its Audit, Human Resources and Nominating and Corporate Governance Committees. All of the foregoing documents are posted on the Corporate Governance page of the Company's website. We will also provide copies of such information free of charge upon request to Shareholder Relations at the address listed above.

ITEM 1A. *Risk Factors*

Our financial and operating results are subject to a number of factors, many of which are not within our control. Although we have tried to discuss key risk factors below, please be aware that other risks may prove to be important in the future. These factors include the following:

We are subject to regulation by each state in which we operate that affect our operations and financial results.

Our natural gas utility business is subject to various regulated returns on its rate base in each of the 12 states in which we operate. We monitor the allowed rates of return and our effectiveness in earning such rates and initiate rate proceedings or operating changes as we believe are needed. In addition, in the normal course of the regulatory environment, assets may be placed in service and historical test periods established before rate cases that could adjust our returns can be filed. Once rate cases are filed, regulatory bodies have the authority to suspend implementation of the new rates while studying the cases. Because of this process, we must suffer the negative financial effects of having placed assets in service without the benefit of rate relief, which is commonly referred to as "regulatory lag". In addition, rate cases involve a risk of rate reduction, and once rates have been approved, they are still subject to challenge for their reasonableness by appropriate

regulatory authorities. Our debt and equity financings are also subject to approval by regulatory bodies in several states which could limit our ability to take advantage of favorable market conditions.

Our business could also be affected by deregulation initiatives, including the development of unbundling initiatives in the natural gas industry. Unbundling is the separation of the provision and pricing of local distribution gas services into discrete components. It typically focuses on the separation of the distribution and gas supply components and the resulting opening of the regulated components of sales services to alternative unregulated suppliers of those services. Although we believe that our enhanced technology and distribution system infrastructures have positively positioned us, we cannot provide assurance that there would be no significant adverse effect on our business should unbundling or further deregulation of the natural gas distribution service business occur.

Our operations are weather sensitive.

Our natural gas utility sales volumes and related revenues are correlated with heating requirements that result from cold winter weather. Although beginning in the 2006-2007 winter heating season, we will have weather-normalized rates for over 90 percent of our residential and commercial meters that should substantially eliminate the adverse effects of warmer-than-normal weather for meters in those service areas, our utility operating results will continue to vary with the temperatures during the winter heating season. In addition, sustained cold weather could adversely affect our natural gas marketing operations as we may be required to purchase gas at spot rates in a rising market to obtain sufficient volumes to fulfill some customer contracts.

The concentration of our distribution, pipeline and storage operations in the State of Texas have increased the exposure of our operations and financial results to adverse weather, economic conditions or regulatory decisions in Texas.

As a result of our acquisition of the distribution, pipeline and storage operations of TXU Gas in October 2004, over 50 percent of our natural gas distribution customers and most of our pipeline and storage assets and operations are now located in the State of Texas. This concentration of our business in Texas means that our operations and financial results are subject to greater impact than before from changes in the Texas economy in general as well as the weather in our service areas of the state during the winter heating season. Our financial results in fiscal 2006 were adversely affected by warm weather in Texas. In addition, the impact of any adverse rate or other regulatory decisions by state or local regulatory authorities in Texas will also be greater. The hearing in the Mid-Tex Division's first rate case since the TXU Gas acquisition has just concluded. In the proceeding, we are seeking additional revenue and several rate design changes. A rate reduction or other significant, adverse decision by the Texas Railroad Commission in the proceeding could materially affect our financial results.

We are subject to environmental regulation which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could be significant to our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations. Such revised or new regulations could result in increased compliance costs or additional operating restrictions which could adversely affect our business, financial condition and results of operations.

Our operations are exposed to market risks that are beyond our control which could adversely affect our financial results.

Our risk management operations are subject to market risks beyond our control including market liquidity, commodity price volatility and counterparty creditworthiness.

Although we maintain a risk management policy, we may not be able to completely offset the price risk associated with volatile gas prices or the risk in our natural gas marketing and pipeline and storage segments which could lead to volatility in our earnings. Physical trading also introduces price risk on any net open positions at the end of each trading day, as well as volatility resulting from intra-day fluctuations of gas prices and the potential for daily price movements between the time natural gas is purchased or sold for future delivery and the time the related purchase or sale is hedged. Although we manage our business to maintain no open positions, there are times when limited net open positions related to our physical storage may occur on a short-term basis. The determination of our net open position as of any day requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. Net open positions may increase volatility in our financial condition or results of operations if market prices move in a significantly favorable or unfavorable manner because the timing of the recognition of profits or losses on the hedges for financial accounting purposes does not always match up with the timing of the economic profits or losses on the item being hedged. This volatility may occur with a resulting increase or decrease in earnings or losses, even though the expected profit margin is essentially unchanged from the date the transactions were consummated. Further, if the local physical markets in which we trade do not move consistently with the NYMEX futures market, we could experience increased volatility in the financial results of our natural gas marketing and pipeline and storage segments.

Our natural gas marketing and pipeline and storage segments manage margins and limit risk exposure on the sale of natural gas inventory or the offsetting fixed-price purchase or sale commitments for physical quantities of natural gas through the use of a variety of financial derivatives. However, contractual limitations could adversely affect our ability to withdraw gas from storage which could cause us to purchase gas at spot prices in a rising market to obtain sufficient volumes to fulfill customer contracts. We could also realize financial losses on our efforts to limit risk as a result of volatility in the market prices of the underlying commodities or if a counterparty fails to perform under a contract. In addition, adverse changes in the creditworthiness of our counterparties could limit the level of trading activities with these parties and increase the risk that these parties may not perform under a contract.

We are also subject to interest rate risk on our commercial paper borrowings and floating rate debt. In the past few years, we have been operating in a relatively low interest-rate environment with both short and long-term interest rates being relatively low compared to past interest rates. However, in the past two years, the Federal Reserve has taken actions that have resulted in increases in short-term interest rates. Future increases in interest rates could adversely affect our future financial results.

The execution of our business plan could be affected by an inability to access financial markets.

We rely upon access to both short-term and long-term capital markets to satisfy our liquidity requirements. Adverse changes in the economy or these markets, the overall health of the industries in which we operate and changes to our credit ratings could limit access to these markets, increase our cost of capital or restrict the execution of our business plan.

Our long-term debt is currently rated as "investment grade" by Standard & Poor's Corporation (S&P), Moody's Investors Services, Inc. (Moody's) and Fitch Ratings, Ltd. (Fitch), the three credit rating agencies that rate our long-term debt securities. There can be no assurance that these rating agencies will maintain investment grade ratings for our long-term debt. If we were to lose our investment-grade rating, the commercial paper markets and the commodity derivatives markets could become unavailable to us. This would increase our borrowing costs for working capital and reduce the borrowing capacity of our gas marketing affiliate. In addition, if our commercial paper ratings were lowered, it would increase the cost of commercial

paper financing and could reduce or eliminate our ability to access the commercial paper markets. If we are unable to issue commercial paper, we intend to borrow under our bank credit facilities to meet our working capital needs. This would increase the cost of our working capital financing.

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

Inflation has caused increases in some of our operating expenses and has required assets to be replaced at higher costs. We have a process in place to continually review the adequacy of our utility gas rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those gas rates. Historically, we have been able to budget and control operating expenses and investments within the amounts authorized to be collected in rates and intend to continue to do so. However, the ability to control expenses is an important factor that could influence future results.

Rapid increases in the price of purchased gas, which occurred recently and in some prior years, cause us to experience a significant increase in short-term debt because we must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow our utility collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher than normal accounts receivable. This could result in higher short-term debt levels, greater collection efforts and increased bad debt expense.

Our operations are subject to increased competition.

In the residential and commercial customer markets, our regulated utility operations compete with other energy products, such as electricity and propane. Our primary product competition is with electricity for heating, water heating and cooking. Increases in the price of natural gas could negatively impact our competitive position by decreasing the price benefits of natural gas to the consumer. This could adversely impact our business if as a result, our customer growth slows, resulting in reduced ability to make capital expenditures, or if our customers further conserve their use of gas, resulting in reduced gas purchases and customer billings.

In the case of industrial customers, such as manufacturing plants, and agricultural customers, adverse economic conditions, including higher gas costs, could cause these customers to use alternative sources of energy, such as electricity, or bypass our systems in favor of special competitive contracts with lower per-unit costs. Our pipeline and storage operations currently face limited competition from other existing intrastate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers. However, competition may increase if new intrastate pipelines are constructed near our existing facilities.

The cost of providing pension and postretirement health care benefits is subject to changes in pension fund values and changing demographics and may have a material adverse effect on our financial results.

We provide a cash-balance pension plan for the benefit of eligible full-time employees as well as postretirement health care benefits to eligible full-time employees. Our costs of providing such benefits is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancy of beneficiaries and an expected increase in the number of eligible former employees over the next five to ten years, and various actuarial calculations and assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates and other factors. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods.

Our growth in the future may be limited by the nature of our business, which requires extensive capital spending.

We must continually build additional capacity in our natural gas distribution system to maintain the growth in the number of our customers. The cost of adding this capacity may be affected by a number of factors, including the general state of the economy and weather. Our cash flows from operations are generally not sufficient to supply funding for all our capital expenditures including the financing of the costs of this new construction along with capital expenditures necessary to maintain our existing natural gas system. As a result, we must fund at least a portion of these costs through borrowing funds from third party lenders, the cost of which is dependent on the interest rates at the time. This in turn may limit our ability to connect new customers to our system due to constraints on the amount of funds we can invest in our infrastructure.

Distributing and storing natural gas involve risks that may result in accidents and additional operating costs.

Our natural gas distribution business involves a number of hazards and operating risks that cannot be completely avoided, such as leaks, accidents and operational problems, which could cause loss of human life, as well as substantial financial losses resulting from property damage, damage to the environment and to our operations. We do have liability and property insurance coverage in place for many of these hazards and risks. However, because our pipeline, storage and distribution facilities are near or are in populated areas, any loss of human life or adverse financial results resulting from such events could be large. If these events were not fully covered by insurance, our financial position and results of operations could be adversely affected.

Natural disasters and terrorist activities and other actions could adversely affect our operations or financial results.

Natural disasters are always a threat to our assets and operations. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Also, companies in our industry may face a heightened risk of exposure to actual acts of terrorism, which could subject our operations to increased risks. As a result, the availability of insurance covering such risks may be more limited, which could increase the risk that an event could adversely affect future financial results.

ITEM 1B. *Unresolved Staff Comments*

Not applicable.

ITEM 2. *Properties*

Distribution, transmission and related assets

At September 30, 2006, our utility segment owned an aggregate of 75,869 miles of underground distribution and transmission mains throughout our gas distribution systems. These mains are located on easements or rights-of-way which generally provide for perpetual use. We maintain our mains through a program of continuous inspection and repair and believe that our system of mains is in good condition. At September 30, 2006, our pipeline and storage segment owned 6,127 miles of gas transmission and gathering lines.

Our utility segment also holds franchises granted by the incorporated cities and towns that we serve. At September 30, 2006, we held 1,103 franchises having terms generally ranging from five to 35 years. A significant number of our franchises expire each year, which require renewal prior to the end of their terms. We believe that we will be able to renew our franchises as they expire.

Storage Assets

Our utility and pipeline and storage segments own underground gas storage facilities in several states to supplement the supply of natural gas in periods of peak demand. The following table summarizes certain information regarding our underground gas storage facilities:

State	Usable Capacity (Mcf)	Cushion Gas (Mcf)[1]	Total Capacity (Mcf)	Maximum Daily Delivery Capability (Mcf)
Utility Segment				
Kentucky	4,442,696	6,322,283	10,764,979	109,100
Kansas	3,639,000	2,640,000	6,279,000	55,000
Mississippi	1,544,633	2,181,737	3,726,370	48,000
Georgia	450,000	50,000	500,000	30,000
Total Utility Segment	10,076,329	11,194,020	21,270,349	242,100
Pipeline and Storage Segment				
Texas	39,128,475	13,128,025	52,256,500	1,235,000
Kentucky	3,492,900	3,295,000	6,787,900	71,000
Louisiana	438,583	300,973	739,556	56,000
Total Pipeline and Storage Segment	43,059,958	16,723,998	59,783,956	1,362,000
Total	53,136,287	27,918,018	81,054,305	1,604,100

[1] Cushion gas represents the volume of gas that must be retained in a facility to maintain reservoir pressure.

Additionally, we contract for storage service in underground storage facilities on many of the interstate pipelines serving us to supplement our proprietary storage capacity. The following table summarizes our contracted storage capacity:

Division/Company	Contractor	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MMBtu)[1]
Utility Segment			
Colorado-Kansas Division	Southern Star Central Pipeline	2,719,101	82,397
	Tenaska Marketing Ventures	1,000,000	10,400
	Colorado Interstate Gas Company	422,142	12,985
	Kinder Morgan, Inc.	67,500	1,500
	Centerpoint Energy Gas Transmission	28,500	950
Kentucky Division	Texas Gas Transmission	3,841,150	41,060
	Tennessee Gas Pipeline Company	1,313,538	22,698
Louisiana Division	Gulf South	1,978,020	98,901
	Jefferson Island Storage & Hub	600,000	60,000
	Acadian Natural Gas Company	33,276	2,234
	Tennessee Gas Pipeline Company	18,776	329
	Southern Natural Gas Company	12,945	261
	Trunkline Gas Company	3,105	41
Mid-States Division	Atmos Energy Marketing	1,993,543	16,634
	Southern Natural Gas Company	1,453,265	29,345
	Panhandle Eastern Pipeline	1,035,462	15,721
	Tennessee Gas Pipeline Company	835,674	20,000
	Texas Eastern Transmission Company	753,969	11,303
	Gallagher Drilling Company[2]	640,000	5,000
	ANR Pipeline Company	629,480	11,200
	Dominion	609,008	8,136
	Transco	568,674	12,710
	Virginia Gas Pipeline Company	380,000	23,000
	East Tennessee	339,900	52,633
	Natural Gas Pipeline Company	312,750	5,580
	Texas Gas Transmission	239,576	7,495
	CMS Trunkline Gas Company	220,455	2,940
	MRT Energy Marketing	137,493	2,395
Mississippi Division	Gulf South	1,237,500	61,875
	Southern Natural Gas Company	1,049,436	21,191
	Texas Gas Transmission	826,390	36,420
	Texas Eastern	518,220	8,637
	Atmos Energy Marketing	400,000	40,000
	Trunkline Gas Company	24,840	331
	Tennessee Gas Pipeline Company	3,394	113
West Texas Division	ONEOK Texas Gas Storage LLP	1,125,000	50,000
Total Utility Segment		27,372,082	776,415

See footnotes on the following page.

Division/Company	Contractor	Maximum Storage Quantity (MMBtu)	Maximum Daily Withdrawal Quantity (MMBtu)[1]
Natural Gas Marketing Segment			
Atmos Energy Marketing, LLC			
	Gulf South	5,992,015	85,686
	Egan	1,500,000	90,000
	Atmos Pipeline — Texas	1,000,000	24,000
	Texas Eastern Transmission Company	544,841	5,532
	East Tennessee	250,000	12,500
	National Fuel	223,080	2,028
	Virginia Gas Pipeline Company	170,000	17,000
	Dominion	56,910	929
Total Natural Gas Marketing Segment		9,736,846	237,675
Pipeline and Storage Segment			
Trans Louisiana Gas Pipeline, Inc.	Gulf South Pipeline Company	750,000	30,000
	Bridgeline Gas Distribution LLC	300,000	30,000
Total Pipeline and Storage Segment		1,050,000	60,000
Total Contracted Storage Capacity		38,158,928	1,074,090

(1) Maximum daily withdrawal quantity (MDWQ) amounts will fluctuate depending upon the season and the month. Unless otherwise noted, MDWQ amounts represent the MDWQ amounts as of November 1, which is the beginning of the winter heating season.

(2) We contract for storage service in two underground storage facilities, Wiseman and Ellis, from this company.

Other facilities

Our utility segment owns and operates one propane peak shaving plant with a total capacity of approximately 180,000 gallons that can produce an equivalent of approximately 3,300 Mcf daily.

Offices

Our administrative offices are consolidated in a leased facility in Dallas, Texas. We also maintain field offices throughout our distribution system, the majority of which are located in leased facilities. Our nonutility operations are headquartered in Houston, Texas, with offices in Houston and other locations, primarily in leased facilities.

ITEM 3. *Legal Proceedings*

See Note 13 to the consolidated financial statements.

ITEM 4. *Submission of Matters to a Vote of Security Holders*

No matters were submitted to a vote of security holders during the fourth quarter of fiscal 2006.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information as of September 30, 2006, regarding the executive officers of the Company. It is followed by a brief description of the business experience of each executive officer.

Name	Age	Years of Service	Office Currently Held
Robert W. Best	59	9	Chairman, President and Chief Executive Officer
Kim R. Cocklin	55	—	Senior Vice President, Utility Operations
R. Earl Fischer	67	44	Senior Vice President, Utility Operations
Louis P. Gregory	51	6	Senior Vice President and General Counsel
Mark H. Johnson	47	5	Senior Vice President, Nonutility Operations and President, Atmos Energy Marketing, LLC
Wynn D. McGregor	53	18	Senior Vice President, Human Resources
John P. Reddy	53	8	Senior Vice President and Chief Financial Officer

Robert W. Best was named Chairman of the Board, President and Chief Executive Officer in March 1997.

Kim R. Cocklin joined the Company in June 2006 as Senior Vice President, Utility Operations to succeed R. Earl Fischer, who retired from the Company on September 30, 2006. Prior to joining the Company, Mr. Cocklin served as Senior Vice President, General Counsel and Chief Compliance Officer of Piedmont Natural Gas Company from February 2003 to May 2006. Prior to joining Piedmont, Mr. Cocklin was with Williams Gas Pipeline from 1995 to January 2003, where he served in various capacities, including serving as Vice President for rates, regulatory and business development for all of the Williams Gas pipelines from 2001 to January 2003.

R. Earl Fischer was named Senior Vice President, Utility Operations in May 2000. Mr. Fischer previously served the Company as President of the Mid-Tex Division from October 2004 to October 2005. Mr. Fischer retired from the Company on September 30, 2006.

Louis P. Gregory was named Senior Vice President and General Counsel in September 2000.

Mark H. Johnson was named Senior Vice President, Nonutility Operations in April 2006 and President of Atmos Energy Holdings, Inc., and Atmos Energy Marketing, LLC, in April 2005. Mr. Johnson previously served the Company as Vice President, Nonutility Operations from October 2005 to March 2006 and as Executive Vice President of Atmos Energy Marketing from October 2003 to March 2005. Mr. Johnson joined Atmos Energy Marketing's predecessor, Woodward Marketing, L.L.C., in 1992 as Vice President of Marketing and Operations and was later promoted to Senior Vice President of Marketing for the Midwest and Gulf Coast. Mr. Johnson succeeded JD Woodward III who retired from the Company effective April 1, 2006.

Wynn D. McGregor was named Senior Vice President, Human Resources in October 2005. He previously served the Company as Vice President, Human Resources from January 1994 to September 2005.

John P. Reddy was named Senior Vice President and Chief Financial Officer in September 2000.

PART II

ITEM 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Our stock trades on the New York Stock Exchange under the trading symbol "ATO." The high and low sale prices and dividends paid per share of our common stock for fiscal 2006 and 2005 are listed below. The high and low prices listed are the closing NYSE quotes for shares of our common stock:

	2006			2005		
	High	Low	Dividends Paid	High	Low	Dividends Paid
Quarter ended:						
December 31	$28.36	$25.79	$.315	$27.43	$24.85	$.310
March 31	27.00	26.10	.315	29.09	26.19	.310
June 30	27.91	26.00	.315	28.87	25.94	.310
September 30	29.11	27.96	.315	29.76	28.23	.310
			$1.26			$1.24

Dividends are payable at the discretion of our Board of Directors out of legally available funds and are also subject to restriction under the terms of our First Mortgage Bond agreement. See Note 6 to the consolidated financial statements. The Board of Directors typically declares dividends in the same fiscal quarter in which they are paid. The number of record holders of our common stock on October 31, 2006 was 24,425. Future payments of dividends, and the amounts of these dividends, will depend on our financial condition, results of operations, capital requirements and other factors. We sold no securities during fiscal 2006 that were not registered under the Securities Act of 1933, as amended.

The following table sets forth the number of securities authorized for issuance under our equity compensation plans at September 30, 2006.

	Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) (c)
Equity compensation plans approved by security holders:			
Long-Term Incentive Plan	1,017,152	$22.57	731,745
Long-Term Stock Plan for the Mid-States Division	—	—	168,550
Total equity compensation plans approved by security holders	1,017,152	22.57	900,295
Equity compensation plans not approved by security holders	—	—	—
Total	1,017,152	$22.57	900,295

ITEM 6. *Selected Financial Data*

The following table sets forth selected financial data of the Company and should be read in conjunction with the consolidated financial statements included herein.

	Year Ended September 30				
	2006[1]	2005[2]	2004[3]	2003[4]	2002
	(In thousands, except per share data and ratios)				
Results of Operations					
Operating revenues	$6,152,363	$4,961,873	$2,920,037	$2,799,916	$1,650,964
Gross profit	1,216,570	1,117,637	562,191	534,976	431,140
Operating expenses[1]	833,954	768,982	368,496	347,136	275,809
Operating income	382,616	348,655	193,695	187,840	155,331
Miscellaneous income (expense)[3]	881	2,021	9,507	2,191	(1,321)
Interest charges	146,607	132,658	65,437	63,660	59,174
Income before income taxes and cumulative effect of accounting change	236,890	218,018	137,765	126,371	94,836
Cumulative effect of accounting change, net income tax benefit	—	—	—	(7,773)	—
Income tax expense	89,153	82,233	51,538	46,910	35,180
Net income	$ 147,737	$ 135,785	$ 86,227	$ 71,688	$ 59,656
Weighted average diluted shares outstanding	81,390	79,012	54,416	46,496	41,250
Diluted net income per share	$ 1.82	$ 1.72	$ 1.58	$ 1.54	$ 1.45
Cash flows from operations	311,449	386,944	270,734	49,541	297,395
Cash dividends paid per share	$ 1.26	$ 1.24	$ 1.22	$ 1.20	$ 1.18
Total utility throughput (MMcf)	393,995	411,134	246,033	247,965	208,541
Total natural gas marketing sales volumes (MMcf)	283,962	238,097	222,572	225,961	204,027
Total pipeline transportation volumes (MMcf)	420,217	383,377	—	—	—
Financial Condition					
Net property, plant and equipment[5]	$3,629,156	$3,374,367	$1,722,521	$1,624,394	$1,380,070
Working capital[5]	(1,616)	151,675	283,310	16,248	(139,150)
Total assets[5][6]	5,719,547	5,653,527	2,912,627	2,625,495	2,059,631
Short-term debt, inclusive of current maturities of long-term debt	385,602	148,073	5,908	127,940	167,771
Capitalization:					
Shareholders' equity	1,648,098	1,602,422	1,133,459	857,517	573,235
Long-term debt (excluding current maturities)	2,180,362	2,183,104	861,311	862,500	668,959
Total capitalization	3,828,460	3,785,526	1,994,770	1,720,017	1,242,194
Capital expenditures	425,324	333,183	190,285	159,439	132,252
Financial Ratios					
Capitalization ratio[6]	39.1%	40.7%	56.7%	46.4%	40.7%
Return on average shareholders' equity[7]	8.9%	9.0%	9.1%	9.9%	9.9%

See footnotes on the following page.

(1) Financial results for 2006 include a $22.9 million pre-tax loss for the impairment of the West Texas Division's irrigation assets.

(2) Financial results for 2005 include the results of the Mid-Tex Division and Atmos Pipeline — Texas Division from October 1, 2004, the date of acquisition.

(3) Financial results for 2004 include a $5.9 million pre-tax gain on the sale of our interest in U.S. Propane, L.P. and Heritage Propane Partners, L.P.

(4) Financial results for fiscal 2003 include the results of MVG from December 3, 2002, the date of acquisition.

(5) Beginning in 2004, we reclassified our regulatory cost of removal obligation from accumulated depreciation to a liability. The amounts presented above for property, plant and equipment, working capital and total assets reflect this reclassification for all periods presented. These reclassifications did not impact our financial position, results of operations or cash flows as of and for the years ended September 30, 2003 and 2002.

(6) The capitalization ratio is calculated by dividing shareholders' equity by the sum of total capitalization and short-term debt, inclusive of current maturities of long-term debt. Beginning in 2004 we reclassified our original issue discount costs from deferred charges and other assets to long-term debt. This reclassification did not materially impact our capitalization or our capitalization ratio as of September 30, 2003 and 2002.

(7) The return on average shareholders' equity is calculated by dividing current year net income by the average of shareholders' equity for the previous five quarters.

The following table presents a condensed income statement by segment for the year ended September 30, 2006.

	Year Ended September 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
			(In thousands)			
Operating revenues from external parties	$3,649,851	$2,418,856	$ 81,857	$1,799	$ —	$6,152,363
Intersegment revenues	740	737,668	78,710	4,099	(821,217)	—
	3,650,591	3,156,524	160,567	5,898	(821,217)	6,152,363
Purchased gas cost	2,725,534	3,025,897	838	—	(816,476)	4,935,793
Gross profit	925,057	130,627	159,729	5,898	(4,741)	1,216,570
Operating expenses	723,163	28,392	81,871	5,506	(4,978)	833,954
Operating income	201,894	102,235	77,858	392	237	382,616
Miscellaneous income	9,506	2,598	2,554	4,151	(17,928)	881
Interest charges	126,489	8,510	25,331	3,968	(17,691)	146,607
Income before income taxes	84,911	96,323	55,081	575	—	236,890
Income tax expense	31,909	37,757	19,457	30	—	89,153
Net income	$ 53,002	$ 58,566	$ 35,624	$ 545	$ —	$ 147,737
Capital expenditures	$ 307,742	$ 909	$116,673	$ —	$ —	$ 425,324

ITEM 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

INTRODUCTION

This section provides management's discussion of the financial condition, changes in financial condition and results of operations of Atmos Energy Corporation and its consolidated subsidiaries with specific information on results of operations and liquidity and capital resources. It includes management's interpretation of our financial results, the factors affecting these results, the major factors expected to affect future operating results and future investment and financing plans. This discussion should be read in conjunction with our consolidated financial statements and notes thereto.

Our performance in the future will primarily depend on the results of our utility and nonutility operations. Several factors exist that could influence our future financial performance, some of which are described in Item 1A above, "Risk Factors". They should be considered in connection with evaluating forward-looking statements contained in this report or otherwise made by or on behalf of us since these factors could cause actual results and conditions to differ materially from those set out in such forward-looking statements.

Cautionary Statement for the Purposes of the Safe Harbor under the Private Securities Litigation Reform Act of 1995

The statements contained in this Annual Report on Form 10-K may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements other than statements of historical fact included in this Report are forward-looking statements made in good faith by us and are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. When used in this Report, or any other of our documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "forecast", "goal", "intend", "objective", "plan", "projection", "seek", "strategy" or similar words are intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed or implied in the statements relating to our strategy, operations, markets, services, rates, recovery of costs, availability of gas supply and other factors. These risks and uncertainties include the following: regulatory trends and decisions, including deregulation initiatives and the impact of rate proceedings before various state regulatory commissions; adverse weather conditions, such as warmer than normal weather in our utility service territories or colder than normal weather that could adversely affect our natural gas marketing activities; the concentration of our distribution, pipeline and storage operations in one state; impact of environmental regulations on our business; market risks beyond our control affecting our risk management activities including market liquidity, commodity price volatility, increasing interest rates and counterparty creditworthiness; our ability to continue to access the capital markets; the effects of inflation and changes in the availability and prices of natural gas, including the volatility of natural gas prices; increased competition from energy suppliers and alternative forms of energy; increased costs of providing pension and postretirement health care benefits; the capital-intensive nature of our distribution business, the inherent hazards and risks involved in operating our distribution business, and other risks and uncertainties discussed herein, especially in Item 1A above, all of which are difficult to predict and many of which are beyond our control. Accordingly, while we believe these forward-looking statements to be reasonable, there can be no assurance that they will approximate actual experience or that the expectations derived from them will be realized. Further, we undertake no obligation to update or revise any of our forward-looking statements whether as a result of new information, future events or otherwise.

OVERVIEW

In fiscal 2006, we earned $147.7 million in net income or $1.82 per diluted share, compared with net income of $135.8 million, or $1.72 per diluted share in fiscal 2005. The nine percent year-over-year increase in net income was primarily attributable strong financial results in our natural gas marketing segment as it was able to capture higher margins in a volatile natural gas market and favorable unrealized mark-to-market gains. Additionally, pipeline and storage net income increased 16 percent compared with the prior year. These positive results helped overcome the adverse effects on our utility segment of weather (adjusted for WNA) that

was 13 percent warmer than normal, the adverse effect of Hurricane Katrina on our Louisiana Division and a non-recurring, noncash charge to impair certain assets. Our utility operations contributed $53.0 million ($0.65 per diluted share) or 36 percent to fiscal 2006 results. Our nonutility operations, comprised of our natural gas marketing, pipeline and storage and other nonutility segments, contributed $94.7 million ($1.17 per diluted share) or 64 percent to fiscal 2006 results. Key financial and other events for fiscal 2006 include the following:

- Our utility segment net income decreased $28.1 million during the year ended September 30, 2006 compared with the year ended September 30, 2005. The decrease primarily resulted from the impact of weather, as adjusted for jurisdictions with weather-normalized rates, that was two percent warmer than the prior-year period and 13 percent warmer than normal, coupled with higher operating expenses. Utility segment results also reflect a $14.6 million net of tax charge associated with the impairment of the West Texas Division's irrigation assets.
- During fiscal 2006, our Louisiana and Mid-Tex divisions received WNA in their rate designs that will go into effect in fiscal 2007. After receiving WNA in these two jurisdictions, we will have weather protection for over 90 percent of our residential and commercial meters for the 2006-2007 winter heating season.
- Our natural gas marketing segment net income increased $35.2 million during the year ended September 30, 2006 compared with the year ended September 30, 2005. The increase in natural gas marketing net income primarily reflects an increase in our unrealized margin of $43.2 million and increased realized margins due to our ability to capture higher margins in a volatile natural gas market. These increases were partially offset by a $7.4 million increase in operating expenses and increased interest charges resulting from increased short-term borrowings to fund working capital needs.
- Our pipeline and storage segment net income increased $5.0 million during the year ended September 30, 2006 compared with the year ended September 30, 2005. Increased gross profit margin resulting from higher transportation and related services margins coupled with increased throughput on our Atmos Pipeline-Texas system and Atmos Pipeline & Storage, LLC's ability to capture more favorable arbitrage spreads in its asset management contracts were partially offset by higher operating expenses.
- Our capitalization ratio at September 30, 2006 was 60.9 percent compared with 59.3 percent at September 30, 2005 reflecting the impact of increased short-term debt borrowings to fund working capital needs partially offset by current-year net income.
- For the year ended September 30, 2006, we generated $311.4 million in operating cash flow compared with $386.9 million for the year ended September 30, 2005, reflecting the adverse impact of high natural gas costs on our working capital.
- Capital expenditures increased to $425.3 million from $333.2 million primarily reflecting increased capital spending for various pipeline expansion projects in our Atmos Pipeline — Texas Division.

Our financial performance is discussed in greater detail below in Results of Operations.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States. Preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses and the related disclosures of contingent assets and liabilities. We based our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances. On an ongoing basis, we evaluate our estimates, including those related to risk management and trading activities, allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Our critical accounting policies are reviewed by the Audit Committee quarterly. Actual results may differ from estimates.

Regulation — Our utility operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our regulated utility operations are accounted for in accordance with Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation.* This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in their financial statements. We record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. As a result, certain costs that would normally be expensed under accounting principles generally accepted in the United States are permitted to be capitalized because they can be recovered through rates. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our utility operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

Revenue recognition — Sales of natural gas to our utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for utility segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulators and are subject to refund. As permitted by SFAS No. 71, we recognize this revenue and establish a reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues.

Allowance for doubtful accounts — For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Derivatives and hedging activities — In our utility segment, we use a combination of storage and financial derivatives to partially insulate us and our natural gas utility customers against gas price volatility

during the winter heating season. The financial derivatives we use in our utility segment are accounted for under the mark-to-market method pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*. Changes in the valuation of these derivatives primarily result from changes in the valuation of the portfolio of contracts, the maturity and settlement of contracts and newly originated transactions. However, because the costs of financial derivatives used in our utility segment will ultimately be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. The changes in the assets and liabilities from risk management activities are recognized in purchased gas cost in the income statement when the related costs are recovered through our rates.

Our natural gas marketing risk management activities are conducted through our natural gas marketing segment. This segment is exposed to risks associated with changes in the market price of natural gas, which we manage through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date. The use of these contracts is subject to our risk management policies, which are monitored for compliance daily.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase or sell physical natural gas and then sell or purchase financial contracts at a price sufficient to cover our carrying costs and provide a gross profit margin. Through the use of transportation and storage services and derivatives, we seek to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Under SFAS 133, natural gas inventory is designated as the hedged item in a fair-value hedge by AEM and Atmos Pipeline and Storage LLC. This inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains or losses in revenue in the period of change. Effective October 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change had no material impact on our financial position on the date of adoption. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains or losses in the period of change. The difference in the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedges (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. Over time, we expect gains and losses on the sale of storage gas inventory to be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. We continually manage our positions and seek to optimize value as market conditions and other circumstances change. We elect to exclude the differential between the spot price used to value our physical inventory and the forward price used to value the financial hedges designated against our physical inventory for purposes of assessing the effectiveness of these fair-value hedges.

Similar to our inventory position, we attempt to mitigate substantially all of the commodity price risk associated with our fixed-price contracts with minimum volume requirements through the use of various offsetting derivatives. Prior to April 2004, these derivatives were not designated as hedges under SFAS 133 because they naturally locked in the economic gross profit margin at the time we entered into the contract. The fixed-price forward and offsetting derivative contracts were marked to market each month with changes in fair value recognized as unrealized gains and losses recorded in revenue in our consolidated statement of income. The unrealized gains and losses were realized as a component of revenue in the period in which we fulfilled the requirements of the fixed-price contract and the derivatives settled. To the extent that the

unrealized gains and losses of the fixed-price forward contracts and the offsetting derivatives did not offset exactly, our earnings experienced some volatility. At delivery, the gains and losses on the fixed-price contracts were offset by gains and losses on the derivatives, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

Effective April 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We designated the offsetting derivative contracts as cash flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts have been recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. Hedge ineffectiveness, to the extent incurred, is reported as a component of revenue.

Additionally, we utilize storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. Although the purpose of these instruments is to either reduce basis or other risks or lock in arbitrage opportunities, these derivative instruments have not been designated as hedges. Accordingly, these derivative instruments are recorded at fair value with all changes in fair value included in revenue in our natural gas marketing segment.

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, unrealized gains and losses associated with the Treasury lock agreements were recorded as a component of accumulated other comprehensive income. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. This realized loss is being recognized as a component of interest expense over the life of the related financing arrangements.

The fair value of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our derivatives. We believe the market prices and models used to value these derivatives represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under then current market conditions.

Impairment assessments — We perform impairment assessments of our goodwill, intangible assets subject to amortization and long-lived assets. We currently have no indefinite-lived intangible assets. We annually evaluate our goodwill balances for impairment during our second fiscal quarter or as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. We have determined our reporting units to be each of our utility divisions and wholly-owned subsidiaries. Goodwill is allocated to the reporting units responsible for the acquisition that gave rise to the goodwill.

The discounted cash flow calculations used to assess goodwill impairment are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

We periodically evaluate whether events or circumstances have occurred that indicate that our intangible assets subject to amortization and other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of these assets by determining whether the carrying value will be recovered through expected future cash flows. These cash flow projections consider various factors such as the timing of the future cash flows and the discount rate and are based upon the best information available at the time the estimate is made. Changes in

these factors could materially affect the cash flow projections and result in the recognition of an impairment charge. An impairment charge is recognized as the difference between the carrying amount and the fair value if the sum of the undiscounted cash flows is less than the carrying value of the related asset.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Aa bond index, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of our annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan cost over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our postretirement net expense based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension cost ultimately recognized. A 0.25 percent change in our discount rate would impact our pension and postretirement cost by approximately $1.1 million. A 0.25 percent change in our expected rate of return would impact our pension and postretirement cost by approximately $0.8 million.

RESULTS OF OPERATIONS

The following table presents our financial highlights for the three fiscal years ended September 30, 2006:

	For the Year Ended September 30		
	2006	2005	2004
	(In thousands, unless otherwise noted)		
Operating revenues	$6,152,363	$4,961,873	$2,920,037
Gross profit	1,216,570	1,117,637	562,191
Operating expenses	833,954	768,982	368,496
Operating income	382,616	348,655	193,695
Miscellaneous income	881	2,021	9,507
Interest charges	146,607	132,658	65,437
Income before income taxes	236,890	218,018	137,765
Income tax expense	89,153	82,233	51,538
Net income	$ 147,737	$ 135,785	$ 86,227
Utility sales volumes — MMcf	272,033	296,283	173,219
Utility transportation volumes — MMcf	121,962	114,851	72,814
Total utility throughput — MMcf	393,995	411,134	246,033
Natural gas marketing sales volumes — MMcf	283,962	238,097	222,572
Pipeline transportation volumes — MMcf	420,217	383,377	—
Heating Degree Days [1]			
Actual (weighted average)	2,527	2,587	3,271
Percent of normal	87%	89%	96%
Consolidated utility average transportation revenue per Mcf	$ 0.50	$ 0.51	$ 0.42
Consolidated utility average cost of gas per Mcf sold	$ 10.02	$ 7.41	$ 6.55

[1] Adjusted for service areas that have weather normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

The following table shows our operating income by utility division and by segment for the three fiscal years ended September 30, 2006. The presentation of our utility operating income is included for financial reporting purposes and may not be appropriate for ratemaking purposes.

	2006		2005		2004	
	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]	Operating Income	Heating Degree Days Percent of Normal[1]
	(In thousands, except degree day information)					
Colorado-Kansas	$ 22,524	99%	$ 25,157	99%	$ 20,876	99%
Kentucky	14,338	100%	18,657	98%	22,738	98%
Louisiana	27,772	78%	24,819	78%	40,762	93%
Mid-States	35,555	95%	35,687	93%	38,778	95%
Mid-Tex	71,703	72%	84,965	80%	—	—
Mississippi	23,276	102%	19,045	96%	18,709	101%
West Texas	2,215	100%	27,520	99%	22,090	90%
Other	4,511	—	515	—	(4,063)	—
Utility segment	201,894	87%	236,365	89%	159,890	96%
Natural gas marketing segment	102,235	—	40,985	—	27,726	—
Pipeline and storage segment	77,858	—	70,286	—	5,293	—
Other nonutility segment	629	—	1,019	—	786	—
Consolidated operating income	$382,616	87%	$348,655	89%	$193,695	96%

[1] Adjusted for service areas that have weather-normalized operations. For service areas that have weather normalized operations, normal degree days are used instead of actual degree days in computing the total number of heating degree days.

Year ended September 30, 2006 compared with year ended September 30, 2005

Utility segment

Our utility segment has historically contributed 65 to 85 percent of our consolidated net income. However, during fiscal 2006, our utility segment contributed approximately 36 percent of our consolidated net income primarily due to the adverse effect of significantly warmer than normal weather, the adverse effect of Hurricane Katrina and a non-recurring, noncash charge to recognize the impairment of our irrigation assets. The primary factors that impact the results of our utility operations are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas sales to residential, commercial and public-authority customers are affected by winter heating season requirements. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Accordingly, our second fiscal quarter has historically been our most critical earnings quarter with an average of approximately 64 percent of our consolidated net income having been earned in the second quarter during the three most recently completed fiscal years. Additionally, we typically experience higher levels of accounts receivable, accounts payable, gas stored underground and short-term debt balances during the winter heating season due to the seasonal nature of our revenues and the need to purchase and store gas to support these operations. Utility sales to industrial customers are much less weather sensitive.

Changes in the cost of gas impact revenue but do not directly affect our gross profit from utility operations because the fluctuations in gas prices are passed through to our customers. Accordingly, we believe gross profit margin is a better indicator of our financial performance than revenues. However, higher gas costs may cause customers to conserve or, in the case of industrial customers, to use alternative energy sources. Higher gas costs may also adversely impact our accounts receivable collections, resulting in higher bad debt

expense, and may require us to increase borrowings under our credit facilities resulting in higher interest expense.

The effects of weather that is above or below normal are substantially offset through weather normalization adjustments in most of our service areas. WNA allows us to increase the base rate portion of customers' bills when weather is warmer than normal and decrease the base rate when weather is colder than normal. Accordingly, in our WNA service areas, our gross profit margin should be based substantially on the amount of gross profit that would result from normal weather, despite actual weather conditions that may be either warmer or colder than normal.

During fiscal 2006, we received WNA in our two most weather sensitive jurisdictions: the Louisiana and Mid-Tex divisions. With the addition of WNA in these two jurisdictions, we will have weather protection for over 90 percent of our residential and commercial meters for the 2006-2007 winter heating season. Prior to these decisions, there was limited weather protection in these jurisdictions. The Louisiana Division had previously benefited from a higher base customer charge. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal. In May 2006, the LPSC approved a settlement that provided for a modified WNA which provides a partial decoupling mechanism to stabilize this jurisdiction's margins. The approved WNA will cover a period from December to March.

Prior to October 1, 2006, the Mid-Tex Division, which is our largest utility division and contains almost 50 percent of our approximately 3.2 million distribution customers, had benefited from a rate structure that combined a monthly customer charge with a declining block rate schedule to partially mitigate the impact of warmer-than-normal weather on revenue. The combination of the monthly customer charge and the customer billing under the first block of the declining block rate schedule provided for the recovery of a significant portion of our fixed costs for such operations under average weather conditions. However, this rate structure was not as beneficial during periods where weather was significantly warmer than normal.

In July 2006, in connection with the Mid-Tex Division rate proceeding the RRC approved an interim and a permanent WNA effective October 1, 2006 for the Mid-Tex Division. The WNA covers the period from October through May. The interim WNA is based on 30 years of weather history, and the permanent WNA will be modified or adjusted to conform to the rate design that the RRC ultimately approves in the rate proceeding, which proceeding is described in greater detail under Recent Ratemaking Activity.

In the pending rate proceeding before the RRC, we are seeking for our Mid-Tex Division additional annual revenues of approximately $60 million and several rate design changes including revenue stabilization and recovery of the gas cost component of bad debt expense. While the outcome of the Mid-Tex Division's pending rate proceeding before the RRC cannot be predicted with certainty, we believe that we have adequately demonstrated to the RRC that the Mid-Tex Division is entitled to receive an increase in annual revenues and that the remaining rate design changes should be implemented. However, if the RRC were to deny an increase in the Mid-Tex Division's rates or not allow new rate design changes the Mid-Tex Division has requested, our business, financial condition and results of operations could be adversely affected in the future.

Operating income

Utility gross profit increased to $925.1 million for the year ended September 30, 2006 from $907.4 million for the year ended September 30, 2005. Total throughput for our utility business was 394.0 Bcf during the current year compared to 411.1 Bcf in the prior year.

The increase in utility gross profit, despite lower throughput, primarily reflects higher franchise fees and state gross receipts taxes, which are paid by utility customers and have no permanent effect on net income. Additionally, margins increased approximately $14.0 million due to rate increases received from our fiscal 2005 and fiscal 2004 GRIP filings and the recognition of $6.2 million that had been previously deferred in Louisiana following the LPSC's ratification of our agreement in May 2006. These increases were partially offset by approximately $22.9 million due to the impact of significantly warmer than normal weather, particularly in our Mid-Tex and Louisiana divisions. For the year ended September 30, 2006, weather was

13 percent warmer than normal, as adjusted for jurisdictions with weather-normalized operations and two percent warmer than the prior year. In the Mid-Tex and Louisiana Divisions, which did not have weather-normalized rates during the 2005-2006 winter heating season, weather was 28 percent and 22 percent warmer than normal.

Additionally, utility gross profit decreased approximately $2.9 million compared with the prior year in the Louisiana Division due to the impact of Hurricane Katrina. Service has been restored in some areas affected by the storm; however, it is not likely that service will be restored to all of the affected service areas. As more fully described under Recent Ratemaking Activity, we implemented new rates in September 2006 that reflect the impact of Hurricane Katrina.

Operating expenses increased to $723.2 million for the year ended September 30, 2006 from $671.0 million for the year ended September 30, 2005. The increase reflects a $13.3 million increase in taxes, primarily related to franchise fees and state gross receipts taxes, both of which are calculated as a percentage of revenue, and are paid by our customers as a component of their monthly bills. Although these amounts are included as a component of revenue in accordance with our tariffs, timing differences between when these amounts are billed to our customers and when we recognize the associated expense may affect net income favorably or unfavorably on a temporary basis. However, there is no permanent effect on net income.

Operation and maintenance expense, excluding the provision for doubtful accounts, increased $7.8 million primarily due to higher employee costs associated with increased headcount to fill positions that were previously outsourced to a third party, higher medical and dental claims and increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs. Increased line locate, telecommunication and facilities costs also contributed to the overall increase. These increases were partially offset by a reduction in third-party costs for outsourced administrative and meter reading functions that were in-sourced during fiscal 2006. Operation and maintenance expense for the year ended September 30, 2006 was also favorably impacted by the absence of $2.1 million of merger and integration cost amortization associated with the merger of United Cities Gas Company in July 1997, as these costs were fully amortized by December 2004.

The provision for doubtful accounts increased $3.1 million to $20.6 million for the year ended September 30, 2006, compared with $17.5 million in the prior year. The increase was primarily attributable to increased collection risk associated with higher natural gas prices. In the utility segment, the average cost of natural gas for the year ended September 30, 2006 was $10.02 per Mcf, compared with $7.41 per Mcf for the year ended September 30, 2005.

Additionally, during the first quarter of fiscal 2006, the MPSC, in connection with the modification of our rate design described in Recent Ratemaking Activity, decided to allow the recovery of $2.8 million in deferred costs, which it had originally disallowed in its September 2004 decision. This charge was originally recorded in fiscal 2004. This ruling decreased our depreciation expense during the year ended September 30, 2006. This decrease was offset by increased depreciation expense associated with the placement of various capital projects into service during the fiscal year.

Operating expenses were also impacted by $22.9 million noncash charge to impair our West Texas Division's irrigation assets. During the fiscal 2006 fourth quarter, we determined that, as a result of declining irrigation sales primarily associated with our agricultural customers' shift from gas-powered pumps to electric pumps, the West Texas Division's irrigation assets would not be able to generate sufficient future cash flows from operations to recover the net investment in these assets. Therefore, the entire net book value was written off. We will continue to operate these assets until we determine a plan for these assets as we are obligated to provide natural gas services to certain customers served by these assets.

As a result of the aforementioned factors, our utility segment operating income for the year ended September 30, 2006 decreased to $201.9 million from $236.4 million for the year ended September 30, 2005.

Miscellaneous income

Miscellaneous income for the year ended September 30, 2006 was $9.5 million compared to miscellaneous income of $6.8 million for the year ended September 30, 2005. This increase was primarily attributable to increased interest income on intercompany borrowings to our natural gas marketing segment to fund its working capital needs. This increase was partially offset by a $3.3 million charge recorded during the fiscal 2006 second quarter associated with an adverse ruling in Tennessee related to the calculation of a performance-based rate mechanism associated with gas purchases.

Interest charges

Interest charges allocated to the utility segment for the year ended September 30, 2006 increased to $126.5 million from $112.4 million for the year ended September 30, 2005. The increase was attributable to higher average outstanding short-term debt balances to fund natural gas purchases at significantly higher prices coupled with an approximate 200 basis point increase in the interest rate on our $300 million unsecured floating rate Senior Notes due 2007 due to an increase in the three-month LIBOR rate. These increases were partially offset by $4.8 million of interest savings arising from the early payoff of $72.5 million of our First Mortgage Bonds in June 2005.

Natural gas marketing segment

Our natural gas marketing segment aggregates and purchases gas supply, arranges transportation and/or storage logistics and ultimately delivers gas to our customers at competitive prices. To facilitate this process, we utilize proprietary and customer-owned transportation and storage assets to provide the various services our customers request, including furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative products. As a result, our revenues arise from the types of commercial transactions we have structured with our customers and include the value we extract by optimizing the storage and transportation capacity we own or control as well as revenues for services we deliver.

To optimize the storage and transportation capacity we own or control, we participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers by identifying the lowest cost alternative within the natural gas supplies, transportation and markets to which we have access. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from the pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in gross profit margins. Through the use of transportation and storage services and derivative contracts, we seek to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Operating income

Gross profit margin for our natural gas marketing segment consists primarily of marketing activities, which represent the utilization of proprietary and customer-owned transportation and storage assets to provide the various services our customers request, and storage activities, which are derived from the optimization of our managed proprietary and third party storage and transportation assets.

Our natural gas marketing segment's gross profit margin was comprised of the following for the year ended September 30, 2006 and 2005:

	Year Ended September 30	
	2006	2005
	(In thousands, except physical position)	
Storage Activities		
Realized margin	$ 26,225	$ 28,008
Unrealized margin	(1,293)	(14,007)
Total Storage Activities	24,932	14,001
Marketing Activities		
Realized margin	87,236	59,971
Unrealized margin	18,459	(11,999)
Total Marketing Activities	105,695	47,972
Gross profit	$130,627	$ 61,973
Net physical position (Bcf)	14.5	6.9

Our natural gas marketing segment's gross profit margin was $130.6 million for the year ended September 30, 2006 compared to gross profit of $62.0 million for the year ended September 30, 2005. Gross profit margin from our natural gas marketing segment for the year ended September 30, 2006 included an unrealized gain of $17.2 million compared with an unrealized loss of $26.0 million in the prior year. Natural gas marketing sales volumes were 336.5 Bcf during the year ended September 30, 2006 compared with 273.2 Bcf for the prior year. Excluding intersegment sales volumes, natural gas marketing sales volumes were 284.0 Bcf during the current year compared with 238.1 Bcf in the prior year. The increase in consolidated natural gas marketing sales volumes was primarily due to focusing our marketing efforts on higher margin opportunities partially offset by warmer-than-normal weather across our market areas.

Our storage activities generated $24.9 million in gross profit margin for the year ended September 30, 2006 compared to $14.0 million for the year ended September 30, 2005. Lower realized margins in our storage operations were primarily due to the realization of less favorable arbitrage spreads compared with the prior year coupled with increased storage fees. These decreases were partially offset by a decrease in the unrealized loss associated with these operations due to a favorable movement during the year ended September 30, 2006 in the forward natural gas prices used to value the financial hedges designated against our physical inventory and our fixed-price forward contracts. These decreases were also favorably impacted by positive basis ineffectiveness resulting from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the derivative instruments designated as a fair value hedge. These results were magnified by a 7.6 Bcf increase in our net physical position at September 30, 2006 compared to the prior year. We continually seek opportunities to increase the amount of our storage capacity. To the extent we obtain and utilize new capacity and experience price volatility, the amount of our unrealized storage contribution could increase in future periods.

Our marketing activities generated $105.7 million in gross profit margin for the year ended September 30, 2006 compared with $48.0 million for the year ended September 30, 2005. This increase reflects increased realized margins coupled with a favorable unrealized margin variance compared with the prior year. The increase in our realized marketing operations was primarily attributable to successfully capturing increased margins in certain market areas that experienced higher market volatility. The favorable unrealized margin variance was primarily due to favorable movement during the year ended September 30, 2006 in the forward natural gas prices associated with financial derivatives used in these activities and positive basis ineffectiveness on those financial derivatives.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $28.4 million for the

year ended September 30, 2006 from $21.0 million for the year ended September 30, 2005. The increase in operating expense primarily was attributable to an increase in personnel costs due to increased headcount and an increase in regulatory compliance costs.

The improved gross profit margin partially offset by higher operating expenses resulted in an increase in our natural gas marketing segment operating income to $102.2 million for the year ended September 30, 2006 compared with operating income of $41.0 million for the year ended September 30, 2005.

Interest charges

Interest charges allocated to the natural gas marketing segment for the year ended September 30, 2006 increased to $8.5 million from $3.4 million for the year ended September 30, 2005. The increase was attributable to higher average outstanding debt balances to fund natural gas purchases at significantly higher prices.

Pipeline and storage segment

Our pipeline and storage segment consists of the regulated pipeline and storage operations of the Atmos Pipeline — Texas Division and the nonregulated pipeline and storage operations of Atmos Pipeline and Storage, LLC (APS), which were previously included in our other nonutility segment. The Atmos Pipeline — Texas Division transports natural gas to our Mid-Tex Division and for third parties and manages five underground storage reservoirs in Texas. We also provide ancillary services customary in the pipeline industry including parking arrangements, lending and sales of inventory on hand. These operations represent one of the largest intrastate pipeline operations in Texas with a heavy concentration in the established natural gas-producing areas of central, northern and eastern Texas, extending into or near the major producing areas of the Texas Gulf Coast and the Delaware and Val Verde Basins of West Texas. This pipeline system provides access to nine basins located in Texas, which are estimated to contain a substantial portion of the nation's remaining onshore natural gas reserves. APS owns or has an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Similar to our utility segment, our pipeline and storage segment is impacted by seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas. Natural gas transportation requirements are affected by the winter heating season requirements of our customers. This generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either lower net income or net losses during the period from April through September of each year. Further, as the Atmos Pipeline — Texas Division operations supply all of the natural gas for our Mid-Tex Division, the results of this segment are highly dependent upon the natural gas requirements of the Mid-Tex Division. As a regulated pipeline, the operations of the Atmos Pipeline — Texas Division may be impacted by the timing of when costs and expenses are incurred and when these costs and expenses are recovered through its tariffs.

Operating income

Gross profit margin for our pipeline and storage segment primarily consists of transportation margins earned from our Mid-Tex Division and from third parties, other ancillary pipeline services and asset management fees earned by APS. Our pipeline and storage segment's gross profit margin was comprised of the following components for the year ended September 30, 2006 and 2005:

	Year Ended September 30	
	2006	2005
	(In thousands)	
Mid-Tex transportation	$ 69,925	$ 70,089
Third party transportation	58,490	55,376
Asset management fees	10,333	8,559
Storage and park and lend services	11,297	7,451
Unrealized gains (losses)	3,350	(4,730)
Other	6,334	9,733
Gross profit	$159,729	$146,478

Pipeline and storage gross profit increased to $159.7 million for the year ended September 30, 2006 from $146.5 million for the year ended September 30, 2005. Total pipeline transportation volumes were 591.0 Bcf during the year ended September 30, 2006 compared with 563.9 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 420.2 Bcf during the current year compared with 383.4 Bcf in the prior year.

The increase in gross profit was primarily attributable to increased third-party throughput and ancillary services, coupled with increased margins on APS' asset management contracts. Increased third-party throughput on Atmos Pipeline — Texas was primarily attributable to increases in the electric-generation market due to the warmer than normal temperatures during the summer of 2006, increased demand for through-system transportation services due to a widening of pricing differentials between the pipeline's hubs and the impact of Atmos Pipeline — Texas' North Side Loop and other compression projects that were placed into service in June 2006. Storage and parking and lending services on Atmos Pipeline — Texas also increased during fiscal 2006 as a result of the widening of pricing differentials between the pipeline's hubs, which increased the attractiveness of storing gas on the pipeline and our ability to obtain improved margins for these services. The increases on Atmos Pipeline — Texas' system were partially offset by a decrease in margins earned from intercompany transportation services to our Mid-Tex Division due to the significantly warmer than normal weather experienced during fiscal 2006. Additionally, these increases were partially offset by the absence of inventory sales of $3.0 million realized in the prior year.

Increases in APS' margins due to its ability to capture more favorable arbitrage spreads on its asset management contracts also contributed to this segment's improved gross profit margin. These improved margins reflect an unrealized component as APS hedges its risk associated with these contracts. During fiscal 2006, favorable movements in the forward natural gas prices used to value the financial hedges designated against the physical inventory underlying these contracts resulted in an unrealized gain compared with an unrealized loss in the prior year.

Operating expenses increased to $81.9 million for the year ended September 30, 2006 from $76.2 million for the year ended September 30, 2005 due to higher employee benefit costs associated with the increase in headcount, increased pension and postretirement costs resulting from changes in the assumptions used to determine our fiscal 2006 costs, higher facilities costs and higher pipeline integrity costs.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the year ended September 30, 2006 increased to $77.9 million from $70.3 million for the year ended September 30, 2005.

Other nonutility segment

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services, LLC, and Atmos Power Systems, Inc. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services, which began April 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. The revenues of AES represent charges to our utility divisions equal to the costs incurred to provide those services. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Operating income for this segment primarily reflects the leasing income associated with two sales-type lease transactions completed in 2001 and 2002 and was essentially unchanged for the year ended September 30, 2006 compared with the prior year.

Year ended September 30, 2005 compared with year ended September 30, 2004

Utility segment

Operating income

Utility gross profit increased to $907.4 million for the year ended September 30, 2005 from $503.1 million for the year ended September 30, 2004. Total throughput for our utility business was 411.1 Bcf during the current year compared to 246.0 Bcf in the prior year.

The increase in utility gross profit margin primarily reflects the impact of the acquisition of the Mid-Tex Division resulting in an increase in utility gross profit margin and total throughput of $398.2 million and 174.3 Bcf. The $6.1 million increase in the gross profit generated from our other utility operations primarily reflects rate increases in our Mississippi and West Texas divisions that were absent in the prior year coupled with the recognition of a $1.9 million refund to our customers in our Colorado service area in the prior year. Offsetting these increases was a $3.9 million reduction in gross profit in our Louisiana Division due to the impact of Hurricane Katrina. Gross profit margins, particularly in Louisiana, were also adversely impacted by weather (as adjusted for jurisdictions with weather-normalized operations) that was five percent warmer than normal and one percent warmer than the prior year period. Additionally, gross profit margin was adversely impacted by the lack of cold weather in patterns sufficient to encourage customers to increase their heat load consumption and lower irrigation throughput in our West Texas and Colorado-Kansas Divisions.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $671.0 million for the year ended September 30, 2005 from $343.2 million for the year ended September 30, 2004 primarily as a result of the addition of the Mid-Tex Division. Excluding the impact of the Mid-Tex Division, operating expenses for our other utility operations increased $14.5 million primarily due to $2.3 million associated with the effects of Hurricane Katrina, a $7.7 million increase in taxes, other than income, a $2.4 million increase in operation and maintenance expense, including the provision for doubtful accounts, and a $2.1 million increase in depreciation and amortization. Included in taxes other than income taxes are franchise and state gross receipts taxes which are paid by our customers as a component of their monthly bills. Although these amounts are offset in revenues through customer billings, timing differences between when the expense is incurred and is recovered may impact our net income on a temporary basis. However, there is no permanent effect on net income.

As a result of the aforementioned factors, our utility segment operating income for the year ended September 30, 2005 increased to $236.4 million from $159.9 million for the year ended September 30, 2004.

Miscellaneous income

Miscellaneous income increased to $6.8 million for the year ended September 30, 2005 from $5.8 million for the year ended September 30, 2004. The increase was attributable to an increase in interest income earned

on higher cash balances during the current year compared with the prior year partially offset by the recognition of a $0.8 million gain on the sale of a building during the year ended September 30, 2004.

Interest charges

Interest charges allocated to the utility segment for the year ended September 30, 2005 increased to $112.4 million from $65.4 million for the year ended September 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Mid-Tex Division in October 2004. On June 30, 2005, we repaid $72.5 million in principal on five series of our First Mortgage Bonds prior to their scheduled maturities. The early repayment of these bonds resulted in savings of $1.3 million in interest expense in fiscal 2005.

Natural gas marketing segment

Operating income

Our natural gas marketing segment's gross profit margin was comprised of the following for the years ended September 30, 2005 and 2004:

	Year Ended September 30	
	2005	2004
	(In thousands, except physical position)	
Storage Activities		
Realized margin	$ 28,008	$(1,900)
Unrealized margin	(14,007)	357
Total Storage Activities	14,001	(1,543)
Marketing Activities		
Realized margin	59,971	51,347
Unrealized margin	(11,999)	(3,173)
Total Marketing Activities	47,972	48,174
Gross profit	$ 61,973	$46,631
Net physical position (Bcf)	6.9	5.4

Our natural gas marketing segment's gross profit margin was $62.0 million for the year ended September 30, 2005 compared to gross profit of $46.6 million for the year ended September 30, 2004. Gross profit margin from our natural gas marketing segment for the year ended September 30, 2005 included an unrealized loss of $26.0 million compared with an unrealized loss of $2.8 million in the prior year. Natural gas marketing sales volumes were 273.2 Bcf during the year ended September 30, 2005 compared with 265.1 Bcf for the prior year. Excluding intersegment sales volumes, natural gas marketing sales volumes were 238.1 Bcf during the current year compared with 222.6 Bcf in the prior year. The increase in consolidated natural gas marketing sales volumes primarily was attributable to successfully executed marketing strategies into new market areas.

The contribution to gross profit from our storage activities was a gain of $14.0 million for the year ended September 30, 2005 compared to a loss of $1.5 million for the year ended September 30, 2004. The $15.5 million improvement primarily was attributable to a $29.9 million increase in the realized storage contribution for the year ended September 30, 2005 compared to the prior year due to more favorable arbitrage spread opportunities during the current year, partially offset by increased storage fees associated with 9.0 Bcf of newly contracted storage capacity during the third quarter of fiscal 2005. Annual demand charges for this new storage approximate $7.6 million. We may further increase the amount of our storage capacity in the future; therefore, the impact of price volatility on our unrealized storage contribution could become more significant in future periods.

A $14.4 million decrease in the unrealized storage contribution resulted from an unfavorable movement during the year ended September 30, 2005 in the forward indices used to value the storage financial instruments combined with greater physical natural gas storage quantities at September 30, 2005 compared to the prior year also.

Our marketing activities contributed $48.0 million to our gross profit for the year ended September 30, 2005 compared to $48.2 million for the year ended September 30, 2004. The decrease in the marketing contribution primarily was attributable to $12.0 million of unrealized marked-to-market losses associated with basis swaps that were put in place to capture margins in certain volatile market areas. The increase in unrealized marked-to-market losses was partially offset by an increase in our realized marketing margins due to focusing our marketing efforts on higher margin customers and successfully entering into new market areas.

Operating expenses, which include operation and maintenance expense, provision for doubtful accounts, depreciation and amortization expense and taxes other than income taxes, increased to $21.0 million for the year ended September 30, 2005 from $18.9 million for the year ended September 30, 2004. The increase in operating expense was attributable primarily to an increase in labor costs due to increased headcount and an increase in regulatory compliance costs.

The increase in gross profit margin, combined with higher operating expenses, resulted in an increase in our natural gas marketing segment operating income to $41.0 million for the year ended September 30, 2005 compared with operating income of $27.7 million for the year ended September 30, 2004.

Pipeline and storage segment

Operating income

Pipeline and storage gross profit increased to $146.5 million for the year ended September 30, 2005 from $10.4 million for the year ended September 30, 2004. Total pipeline transportation volumes were 563.9 Bcf during the year ended September 30, 2005 compared with 9.4 Bcf for the prior year. Excluding intersegment transportation volumes, total pipeline transportation volumes were 383.4 Bcf during the current year.

The increase in pipeline and storage gross profit margin primarily reflects the impact of the acquisition of the Atmos Pipeline — Texas Division resulting in an increase in pipeline and storage gross profit margin and total transportation volumes of $138.1 million and 375.6 Bcf. Also contributing to Atmos Pipeline — Texas Division's results were higher transportation and related services margin due to significant basis differentials at its three major Texas hubs. The $2.0 million decrease in the gross profit generated by APS primarily reflects a decrease in asset management fees received during fiscal 2005.

Operating expenses increased to $76.2 million for the year ended September 30, 2005 from $5.1 million for the year ended September 30, 2004 due to the addition of $72.2 million in operating expenses associated with the Atmos Pipeline — Texas Division. As the Atmos Pipeline — Texas Division is a regulated entity, franchise and state gross receipts taxes are paid by our customers; thus, these amounts are offset in revenues through customer billings and have no permanent effect on net income. Included in operating expense was $8.9 million associated with taxes other than income taxes, of which $8.3 million was associated with our Atmos Pipeline — Texas Division.

As a result of the aforementioned factors, our pipeline and storage segment operating income for the year ended September 30, 2005 increased to $70.3 million from $5.3 million for the year ended September 30, 2004.

Interest charges

Interest charges allocated to this segment for the year ended September 30, 2005 increased to $24.6 million from $1.1 million for the year ended September 30, 2004. The increase was attributable to the interest expense associated with the issuance of long-term debt to finance the acquisition of the Atmos Pipeline — Texas Division in October 2004.

Other nonutility segment

Operating income for our other nonutility segment primarily reflects the leasing income associated with two sales-type lease transactions completed in fiscal 2001 and 2002. The increase in operating income during the year ended September 30, 2005 reflects the absence of a one-time charge of $0.4 million associated with the wind-down of a noncore business during fiscal 2004.

Miscellaneous income for the year ended September 30, 2005 was $2.6 million compared with $8.3 million for the year ended September 30, 2004. The $5.7 million decrease was attributable primarily to the recognition of a $5.9 million pretax gain on the sale of all remaining limited partnership interests in Heritage Propane Partners, L.P. during fiscal 2004.

LIQUIDITY AND CAPITAL RESOURCES

Our working capital and liquidity for capital expenditure and other cash needs are provided from internally generated funds, borrowings under our credit facilities and commercial paper program and funds raised from the public debt and equity capital markets. We believe that these sources of funds will provide the necessary working capital and liquidity for capital expenditures and other cash needs for fiscal 2007. These facilities are described in greater detail below and in Note 6 to the consolidated financial statements.

Capitalization

The following presents our capitalization as of September 30, 2006 and 2005:

	September 30			
	2006		2005	
	(In thousands, except percentages)			
Short-term debt	$ 382,416	9.1%	$ 144,809	3.7%
Long-term debt	2,183,548	51.8%	2,186,368	55.6%
Shareholders' equity	1,648,098	39.1%	1,602,422	40.7%
Total capitalization, including short-term debt	$4,214,062	100.0%	$3,933,599	100.0%

Total debt as a percentage of total capitalization, including short-term debt, was 60.9 percent and 59.3 percent at September 30, 2006 and 2005. The increase in the debt to capitalization ratio was primarily attributable to an increase in our short-term debt borrowings to fund our working capital needs partially offset by current-year net income. Our ratio of total debt to capitalization is typically greater during the winter heating season as we make additional short-term borrowings to fund natural gas purchases and meet our working capital requirements. Within three to five years, we intend to reduce our capitalization ratio to a target range of 50 to 55 percent through cash flow generated from operations, continued issuance of new common stock under our Direct Stock Purchase Plan and Retirement Savings Plan and access to the equity capital markets.

Cash Flows

Our internally generated funds may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our services, the demand for services, margin requirements resulting from significant changes in commodity prices, operational risks and other factors.

Cash flows from operating activities

Year-over-year changes in our operating cash flows are primarily attributable to working capital changes within our utility segment resulting from the impact of weather, the price of natural gas and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

For the year ended September 30, 2006, we generated operating cash flow of $311.4 million compared with $386.9 million in fiscal 2005 and $270.7 million in fiscal 2004. The significant factors impacting our operating cash flow for the last three fiscal years are summarized below.

Year ended September 30, 2006

Fiscal 2006 operating cash flows reflect the adverse impact of significantly higher natural gas prices. Year-over-year, unfavorable timing of payments for accounts payable and other accrued liabilities reduced operating cash flow by $523.0 million. Partially offsetting these outflows were higher customer collections ($245.1 million) and reduced payments for natural gas inventories ($102.1 million). Additionally, favorable movements in the market indices used to value our natural gas marketing segment risk management assets and liabilities reduced the amount that we were required to deposit in a margin account and therefore favorably affected operating cash flow by $126.3 million.

Year ended September 30, 2005

Fiscal 2005 operating cash flows reflect the effects of a $49.6 million increase in net income and effective working capital management partially offset by higher natural gas prices. Working capital management efforts, which affected the timing of payments for accounts payable and other accrued liabilities, favorably affected operating cash flow by $354.1 million. However, these efforts were partially offset by reduced cash flow generated from accounts receivable changes by $168.9 million, primarily attributable to higher natural gas prices, and an increase in our natural gas inventories attributable to a 13 percent year-over-year increase in natural gas prices coupled with increased natural gas inventory levels, which reduced operating cash flow by $81.8 million. Operating cash flow was also adversely impacted by unfavorable movements in the indices used to value our natural gas marketing segment risk management assets and liabilities, which resulted in a net liability for the segment. Accordingly, under the terms of the associated derivative contracts, we were required to deposit $81.0 million into a margin account.

Year ended September 30, 2004

Fiscal 2004 operating cash flows were favorably impacted by several items. Improved customer collections during fiscal 2004, compared with the prior year, resulted in a $62.2 million increase in operating cash flow. Further, cash used for natural gas inventories decreased by $33.8 million compared with the prior year. The decrease was attributable to lower injections of natural gas into storage, partially offset by higher prices. The reduction in the lag between the time period when we purchase our natural gas and the period in which we can include this cost in our gas rates improved operating cash flow by $65.7 million. Changes in cash held on deposit in margin accounts resulted in an increase in operating cash flow of $25.6 million. This account represents deposits recorded to collateralize certain of our financial derivatives purchased in support of our natural gas marketing activities. The favorable change was attributable to the fact that the fair value of financial instruments held by AEM represented a net asset position at September 30, 2004, which eliminated the need to place cash in margin accounts. Finally, other working capital and other changes improved operating cash flow by $33.9 million. These changes primarily related to various increases in deferred credits and other liabilities, other current liabilities and income taxes payable partially offset by lower deferred income tax expense as compared with the prior year.

Cash flows from investing activities

During the last three years, a substantial portion of our cash resources was used to fund acquisitions and growth projects, our ongoing construction program and improvements to information systems. Our ongoing construction program enables us to provide natural gas distribution services to our existing customer base, to expand our natural gas distribution services into new markets, to enhance the integrity of our pipelines and, more recently, to expand our intrastate pipeline network. In executing our current rate strategy, we are directing discretionary capital spending to jurisdictions that permit us to earn a return on our investment timely. Currently, our Mid-Tex, Louisiana, Mississippi and West Texas utility divisions and our Atmos Pipeline — Texas Division have rate designs that provide the opportunity to include in their rate base approved capital costs on a periodic basis without being required to file a rate case.

For the year ended September 30, 2006, we incurred $425.3 million for capital expenditures compared with $333.2 million for the year ended September 30, 2005 and $190.3 million for the year ended

September 30, 2004. The increase in capital expenditures in fiscal 2006 primarily reflects increased spending associated with our Dallas/Fort Worth Metroplex North Side Loop project and other pipeline expansion projects in our Atmos Pipeline — Texas Division, which were completed during the fiscal 2006 third quarter. Increased capital spending in our Mid-Tex Division for various projects also contributed to the increase in our capital expenditures.

Our cash used for investing activities for the year ended September 30, 2005 reflects the $1.9 billion cash paid for the TXU Gas acquisition including related transaction costs and expenses. Cash flow from investing activities for the year ended September 30, 2004 reflects the receipt of $27.9 million from the sale of our limited and general partnership interests in USP and Heritage Propane Partners, L.P. and from the sale of a building.

Cash flows from financing activities

For the year ended September 30, 2006, our financing activities provided $155.3 million in cash compared with $1.7 billion and $80.4 million provided for the years ended September 30, 2005 and 2004. Our significant financing activities for the years ended September 30, 2006, 2005 and 2004 are summarized as follows:

- In October 2004, we sold 16.1 million shares of common stock, including the underwriters' exercise of their overallotment option of 2.1 million shares, under a shelf registration statement declared effective in September 2004, generating net proceeds of $382 million. Additionally, we issued $1.39 billion of senior unsecured debt under our shelf registration statement with an initial weighted average effective interest rate on these notes of 4.76 percent. The net proceeds from these issuances, combined with the net proceeds from our July 2004 common stock offering were used to finance the acquisition of our Mid-Tex and Atmos Pipeline — Texas divisions and settle Treasury lock agreements, into which we entered to fix the Treasury yield component of the interest cost of financing associated with $875 million of the $1.39 billion long-term debt we issued in October 2004 to fund the acquisition.

- During the years ended September 30, 2006 and 2005, we increased our borrowings under our short-term facilities by $237.6 million and $144.8 million whereas during the year ended September 30, 2004, we repaid a net $118.6 million under our short-term facilities. Net borrowings under our short-term facilities during fiscal 2006 and 2005 reflect the impact of seasonal natural gas purchases and the effect of higher natural gas prices than in prior years.

- We repaid $3.3 million of long-term debt during the year ended September 30, 2006 compared with $103.4 million during the year ended September 30, 2005 and $9.7 million during the year ended September 30, 2004. Fiscal 2005 payments reflected the repayment of $72.5 million of our First Mortgage Bonds. In connection with this repayment we paid a $25.0 million make-whole premium in accordance with the terms of the agreements and accrued interest of approximately $1.0 million. In accordance with regulatory requirements, the premium has been deferred and will be recognized over the remaining original lives of the First Mortgage Bonds that were repaid. The early repayment of these bonds resulted in interest savings of $4.8 million and $1.3 million in fiscal 2006 and 2005.

- During the year ended September 30, 2006, we paid $102.3 million in cash dividends compared with dividend payments of $99.0 million and $66.7 million for the years ended September 30, 2005 and 2004. The increase in dividends paid over the prior year reflects an increase in the dividend rate from $1.24 per share during the year ended September 30, 2005 to $1.26 per share during the year ended September 30, 2006 combined with new share issuances under our various plans.

During the year ended September 30, 2006 we issued 0.9 million shares of common stock which generated net proceeds of $23.3 million. In addition, we granted 0.3 million shares of common stock under

our 1998 Long-Term Incentive Plan to directors, officers and other participants in the plan. The following table shows the number of shares issued for the years ended September 30, 2006, 2005 and 2004:

	For the Year Ended September 30		
	2006	2005	2004
Shares issued:			
Direct stock purchase plan	387,833	450,212	556,856
Retirement savings plan	442,635	441,350	320,313
1998 Long-term incentive plan	366,905	745,788	498,230
Long-term stock plan for Mid-States Division	300	—	6,000
Outside directors stock-for-fee plan	2,442	2,341	3,133
October 2004 Offering	—	16,100,000	—
July 2004 Offering	—	—	9,939,393
Total shares issued	1,200,115	17,739,691	11,323,925

Shelf Registration

In December 2001, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC in January 2002. In July 2004, we sold 9.9 million shares of our common stock, including the underwriters' exercise of their overallotment option, which exhausted the remaining availability under this registration statement.

In August 2004, we filed a registration statement with the SEC to issue, from time to time, up to $2.2 billion in new common stock and/or debt, which became effective in September 2004. In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option of 2.1 million shares, under this registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued $1.39 billion of senior unsecured debt under the registration statement. After issuing the debt and equity in October 2004, we had approximately $401.5 million of availability remaining under this registration statement. However, we are no longer allowed to issue securities under that registration statement by applicable state regulatory commissions since we are in the process of securing their approval to issue a total of $900 million in securities under a new shelf registration statement, including the remaining $401.5 million of capacity carried over from the currently effective registration statement. We intend to file this new registration statement with the SEC in the near future.

Credit Facilities

As of September 30, 2006, we maintained three short-term committed credit facilities totaling $918 million. We also maintain one uncommitted credit facility totaling $25 million and, through AEM, a second uncommitted credit facility that can provide up to $580 million. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the banks. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather. Our cash needs for working capital have increased substantially as a result of the significant increase in the price of natural gas.

In October 2005, our $600 million 364-day committed credit facility expired and was replaced with a $600 million three-year revolving credit facility. In addition, in November 2005, we entered into a new $300 million 364-day revolving credit facility with substantially the same terms as our $600 million credit facility.

In November 2006, we renewed our $300 million 364-day revolving credit facility and were in the process of replacing our three-year $600 million facility with a five-year $600 million revolving credit facility. Both facilities are being renewed with substantially the same terms as their predecessor facilities.

In April 2006, our $18 million committed unsecured credit facility was renewed for one year with no material changes to its terms and pricing. At September 30, 2006, $3.1 million was outstanding under this facility.

As of September 30, 2006, the amount available to us under these credit facilities, net of outstanding letters of credit, was $609.0 million. We believe these credit facilities, combined with our operating cash flows will be sufficient to fund our increased working capital needs. These facilities are described in further detail in Note 6 to the consolidated financial statements.

In November 2005, AEM amended its uncommitted demand working capital credit facility to increase the amount of credit available from $250 million to a maximum of $580 million. In March 2006, AEM amended and extended this uncommitted demand working capital credit facility to March 2007. At September 30, 2006, there were no borrowings outstanding under this facility.

Credit Ratings

Our credit ratings directly affect our ability to obtain short-term and long-term financing, in addition to the cost of such financing. In determining our credit ratings, the rating agencies consider a number of quantitative factors, including debt to total capitalization, operating cash flow relative to outstanding debt, operating cash flow coverage of interest and pension liabilities and funding status. In addition, the rating agencies consider qualitative factors such as consistency of our earnings over time, the quality of our management and business strategy, the risks associated with our utility and nonutility businesses and the regulatory structures that govern our rates in the states where we operate.

Our debt is rated by three rating agencies: Standard & Poor's Corporation (S&P), Moody's Investors Services, Inc. (Moody's) and Fitch Ratings, Ltd. (Fitch). Our current debt ratings are all considered investment grade and are as follows:

	S&P	Moody's	Fitch
Long-term debt	BBB	Baa3	BBB+
Commercial paper	A-2	P-3	F-2

Currently, with respect to our unsecured senior long-term debt, S&P, Moody's and Fitch maintain their stable outlook. None of our ratings is currently under review.

A credit rating is not a recommendation to buy, sell or hold securities. The highest investment grade credit rating for S&P is AAA, Moody's is Aaa and Fitch is AAA. The lowest investment grade credit rating for S&P is BBB−, Moody's is Baa3 and Fitch is BBB−. Our credit ratings may be revised or withdrawn at any time by the rating agencies, and each rating should be evaluated independent of any other rating. There can be no assurance that a rating will remain in effect for any given period of time or that a rating will not be lowered, or withdrawn entirely, by a rating agency if, in its judgment, circumstances so warrant.

Debt Covenants

We were in compliance with all of our debt covenants as of September 30, 2006. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as both our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement

contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity based on our credit rating or other triggering events.

Additional information concerning our debt covenants and how we complied with those covenants is included in Note 6 to the consolidated financial statements.

Contractual Obligations and Commercial Commitments

The following tables provide information about contractual obligations and commercial commitments at September 30, 2006.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
			(In thousands)		
Contractual Obligations					
Long-term debt[1]	$2,186,878	$ 3,186	$305,865	$ 762,762	$1,115,065
Short-term debt[1]	382,416	382,416	—	—	—
Interest charges[2]	1,028,096	121,511	207,939	164,964	533,682
Gas purchase commitments[3]	708,217	560,461	110,793	17,035	19,928
Capital lease obligations[4]	2,777	433	673	477	1,194
Operating leases[4]	176,806	15,959	30,157	26,912	103,778
Demand fees for contracted storage[5]	17,989	8,832	7,257	1,900	—
Demand fees for contracted transportation[6]	27,818	4,269	5,944	5,788	11,817
Derivative obligations[7]	30,945	30,669	276	—	—
Postretirement benefit plan contributions[8]	145,198	11,408	21,584	26,141	86,065
Total contractual obligations	$4,707,140	$1,139,144	$690,488	$1,005,979	$1,871,529

(1) See Note 6 to the consolidated financial statements.

(2) Interest charges were calculated using the stated rate for each debt issuance, or in the case of floating rate debt, the rate that was in effect as of September 30, 2006.

(3) Gas purchase commitments were determined based upon contractually determined volumes at prices estimated based upon the index specified in the contract, adjusted for estimated basis differentials and contractual discounts as of September 30, 2006.

(4) See Note 14 to the consolidated financial statements.

(5) Represents third party contractual demand fees for contracted storage in our natural gas marketing and other utility segments. Contractual demand fees for contracted storage for our utility segment are excluded as these costs are fully recoverable through our purchase gas adjustment mechanisms.

(6) Represents third party contractual demand fees for transportation in our natural gas marketing segment.

(7) Represents liabilities for natural gas commodity derivative contracts that were valued as of September 30, 2006. The ultimate settlement amounts of these remaining liabilities are unknown because they are subject to continuing market risk until the derivative contracts are settled.

(8) Represents expected contributions to our postretirement benefit plans.

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2006, AEM was committed to purchase 61.7 Bcf within one year, 51.2 Bcf between one to three years and 0.8 Bcf after three years under indexed

contracts. AEM was committed to purchase 2.4 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $3.40 to $12.00 per Mcf.

With the exception of our Mid-Tex Division, our utility segment maintains supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract. Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under these contract terms as of September 30, 2006 are reflected in the table above.

In May 2006, we announced plans to form a joint venture with a local natural gas producer to construct a natural gas gathering system in Eastern Kentucky that will originate in Floyd County, Kentucky, and extend north approximately 60 miles to interconnect with the Tennessee Gas Pipeline in Carter County, Kentucky. Tennessee Gas Pipeline's interstate system delivers natural gas to the northeastern United States, including New York City and Boston. Referred to as the Straight Creek Project, the new system is expected to relieve severe gas gathering and transportation constraints that historically have burdened natural gas producers in the area and should improve delivery reliability to natural gas customers. More than a dozen other producers have signed memoranda of understanding to commit gas volumes to the new system and to enter into agreements on commercially reasonable terms.

As currently designed, the project is expected to cost between $75 million to $80 million. In October 2006, FERC issued a declaratory order finding that the Straight Creek Project will be exempt from FERC jurisdiction. Upon receiving all required regulatory approvals, construction is expected to begin in the first half of fiscal 2007, with operations expected to begin in fiscal 2008. Final terms of the joint venture are still being negotiated; however, we anticipate that we will have the ability to consolidate the joint venture.

Risk Management Activities

We conduct risk management activities through our utility, natural gas marketing and pipeline and storage segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to reduce our exposure to unusually large winter-period gas price increases. In our natural gas marketing and pipeline and storage segments, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. To the extent our inventory cost and actual sales and actual purchases do not correlate with the changes in the market indices we use in our hedges, we could experience ineffectiveness or the hedges may no longer meet the accounting requirements for hedge accounting, resulting in the derivatives being treated as mark to market instruments through earnings.

In our natural gas marketing segment, hedge ineffectiveness resulting from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments (referred to as basis ineffectiveness) for both fair value and cash flow hedges was an unrealized gain of approximately $35.5 million for the year ended September 30, 2006 and an unrealized loss of approximately $5.4 million and $1.1 million for the years ended September 30, 2005 and 2004. Actual hedge ineffectiveness resulting from the timing of settlement of physical contracts and the settlement of the derivative instruments (referred to as timing ineffectiveness) resulted in an unrealized gain of approximately $4.4 million and $0.5 million for the years ended September 30, 2006 and 2004 and an unrealized loss of approximately $2.2 million for the year ended September 30, 2005.

In our pipeline and storage segment, timing ineffectiveness resulted in an unrealized loss of approximately $4.7 million and less than $0.1 million for the years ended September 30, 2006 and 2004 and an unrealized gain of approximately $5.2 million for the year ended September 30, 2005.

Finally, during fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-

term debt. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation is being recognized as a component of interest expense over a five year period from the date of settlement, and the remaining amount, approximately $32.2 million, is being recognized as a component of interest expense over a ten year period from the date of settlement. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the consolidated financial statements.

We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Substantially all of our derivative financial instruments are valued using external market quotes and indices. The following table shows the components of the change in fair value of our utility and natural gas marketing derivative contract activities for the year ended September 30, 2006 (in thousands):

	Utility	Natural Gas Marketing
Fair value of contracts at September 30, 2005	$ 93,310	$(61,898)
Contracts realized/settled	25,461	11,106
Fair value of new contracts	(18,651)	—
Other changes in value	(127,329)	65,795
Fair value of contracts at September 30, 2006	$ (27,209)	$ 15,003

The fair value of our utility and natural gas marketing derivative contracts at September 30, 2006, is segregated below by time period and fair value source.

	Fair Value of Contracts at September 30, 2006				
	Maturity in Years				
Source of Fair Value	Less Than 1	1-3	4-5	Greater Than 5	Total Fair Value
	(In thousands)				
Prices actively quoted	$(17,421)	$7,122	$—	$—	$(10,299)
Prices provided by other external sources	(440)	(936)	—	—	(1,376)
Prices based on models and other valuation methods	(255)	(276)	—	—	(531)
Total Fair Value	$(18,116)	$5,910	$—	$—	$(12,206)

Storage and Hedging Outlook

AEM participates in transactions in which it seeks to find and profit from pricing differences that occur over time. AEM purchases physical natural gas and then sells financial contracts at favorable prices to lock in a gross profit margin. AEM is able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Natural gas inventory is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in the period of change. Effective October 1, 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change had no material impact to the Company on the date of adoption. Derivatives associated with our natural gas inventory, which are designated as fair value hedges, are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) are reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges; therefore, the economic gross profit AEM captured in the original transaction remains essentially unchanged.

AEM continually manages its positions to enhance the future economic profit it captured in the original transaction. Therefore, AEM may change its scheduled injection and withdrawal plans from one time period to another based on market conditions or adjust the amount of storage capacity it holds on a discretionary basis in an effort to achieve this objective. AEM monitors the impacts of these profit optimization efforts by estimating the gross profit that it captured and expects to collect through the purchase and sale of physical natural gas and the associated financial derivatives, which we refer to as the economic gross profit. The economic gross profit, combined with the effect of unrealized gains or losses recognized in the financial statements in prior periods, provides a measure of the gross profit that could occur in future periods if AEM's optimization efforts are fully successful. The following table presents AEM's economic gross profit and its potential gross profit for the last three fiscal years.

Period Ending	Net Physical Position (Bcf)	Economic Gross Profit (In millions)	Associated Net Unrealized (Loss) (In millions)	Potential Gross Profit (In millions)
September 30, 2006	14.5	$60.0	$(16.0)	$76.0
September 30, 2005	6.9	$13.1	$(14.8)	$27.9
September 30, 2004	5.4	$12.3	$ (0.8)	$13.1

As of September 30, 2006, based upon AEM's derivatives position and inventory withdrawal schedule, the economic gross profit was $60.0 million. In addition, $16.0 million of net unrealized losses were recorded in the financial statements as of September 30, 2006. Therefore, the potential gross profit was $76.0 million. This potential gross profit amount will not result in an equal increase in future net income as AEM will incur additional storage and other operational expenses to realize this amount.

The economic gross profit is based upon planned injection and withdrawal schedules, and the realization of the economic gross profit is contingent upon the execution of this plan, weather and other execution factors. Since AEM actively manages and optimizes its portfolio to enhance the future profitability of its storage position, it may change its scheduled injection and withdrawal plans from one time period to another based on market conditions. Therefore, we cannot assure that the economic gross profit or the potential gross profit calculated as of September 30, 2006 will be fully realized in the future or in what time period. Further, if we experience operational or other issues which limit our ability to optimally manage our stored gas positions, our earnings could be adversely impacted.

Pension and Postretirement Benefits Obligations

Net Periodic Pension and Postretirement Benefit Costs

For the fiscal year ended September 30, 2006, our total net periodic pension and other benefits costs was $50.0 million, compared with $36.4 million and $26.1 million for the years ended September 30, 2005 and 2004. All of these costs are recoverable through our gas utility rates; however, a portion of these costs is capitalized into our utility rate base. The remaining costs are recorded as a component of operation and maintenance expense.

The increase in total net periodic pension and other benefits cost during fiscal 2006 compared with the prior year primarily reflects changes in assumptions we made during our annual pension plan valuation completed June 30, 2005. The discount rate used to compute the present value of a plan's liabilities generally is based on rates of high-grade corporate bonds with maturities similar to the average period over which the benefits will be paid. In the period leading up to our June 30, 2005 measurement date, these interest rates were declining, which resulted in a 125 basis point reduction in our discount rate to 5.0 percent. This reduction increased the present value of our plan liabilities and associated expenses. Additionally, we reduced the expected return on our pension plan assets by 25 basis points to 8.5 percent, which also increased our pension and postretirement benefit cost.

The increase in total net periodic pension and other benefits cost during fiscal 2005 compared with fiscal 2004 primarily reflects an increase in our service cost associated with the increase in the number of employees

covered by our plans due to the TXU Gas acquisition. Although we did not assume the existing employee benefit liabilities or plans of TXU Gas, for purposes of determining our annual pension cost we agreed to give the transitioned employees credit for years of TXU Gas service under our pension plan. With respect to our postretirement medical plan, we received a credit of $18.9 million against the purchase price to permit us to provide partial past service credits for retiree medical benefits under our retiree medical plan. The $18.9 million credit approximated the actuarially determined present value of the accumulated benefits related to the past service of the transferred employees on the acquisition date.

In addition to the increased number of employees covered by the plans, we changed the assumptions used to determine our fiscal 2005 benefit costs, which resulted in an increase in our net periodic pension and postretirement costs. We increased the discount rate by 25 basis points and we reduced our expected return on our pension plan assets by 25 basis points. These assumption changes decreased the service cost and interest cost and reduced the expected return components of our pension and postretirement benefits costs.

Pension and Postretirement Plan Funding

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2006, we voluntarily contributed $2.9 million to the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees. The current year contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. During fiscal 2005, we voluntarily contributed $3.0 million to the Master Trust to maintain the level of funding we desire relative to our accumulated benefit obligation. We made the contribution because declining high yield corporate bond yields in the period leading up to our June 30, 2005 measurement date resulted in an increase in the present value of our plan liabilities.

We contributed $10.9 million, $10.0 million and $13.8 million to our postretirement benefits plans for the years ended September 30, 2006, 2005 and 2004. The contributions represent the portion of the postretirement costs we are responsible for under the terms of our plan and minimum funding required by our regulators.

Outlook for Fiscal 2007

High grade corporate bond yields increased in the period leading up to our June 30, 2006 measurement date. Therefore, we increased the discount rate for determining our fiscal 2007 pension and benefit costs by 130 basis points to 6.3 percent. However, we reduced the expected return on our pension plan assets by 25 basis points to 8.25 percent. The effect of these assumption changes, coupled with the effects of updating our annual valuation should not significantly affect our fiscal 2007 net pension and postretirement costs compared to fiscal 2006.

We are not required to make a minimum funding contribution to our pension plans during fiscal 2007; nor, at this time, do we intend to make voluntary contributions during 2007. However, we anticipate contributing approximately $11 million to our postretirement medical plans during fiscal 2007.

The projected pension liability, future funding requirements and the amount of pension expense or income recognized for the Plan are subject to change, depending upon the actuarial value of plan assets and the determination of future benefit obligations as of each subsequent actuarial calculation date. These amounts are impacted by actual investment returns, changes in interest rates and changes in the demographic composition of the participants in the plan.

RECENT ACCOUNTING DEVELOPMENTS

Recent accounting developments and their impact on our financial position, results of operations and cash flows are described in Note 2 to the consolidated financial statements.

ITEM 7A. *Quantitative and Qualitative Disclosures About Market Risk*

We are exposed to risks associated with commodity prices and interest rates. Commodity price risk is 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 activities.

We conduct risk management activities through both our utility and natural gas marketing segments. In our utility segment, we use a combination of storage, fixed physical contracts and fixed financial contracts to protect us and our customers against unusually large winter period gas price increases. In our natural gas marketing segment, we manage our exposure to the risk of natural gas price changes and lock in our gross profit margin through a combination of storage and financial derivatives including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Our risk management activities and related accounting treatment are described in further detail in Note 5 to the condensed consolidated financial statements. Additionally, our earnings are affected by changes in short-term interest rates as a result of our issuance of short-term commercial paper, the issuance of floating rate debt in October 2004 and our other short-term borrowings.

Commodity Price Risk

Utility segment

We purchase natural gas for our utility operations. Substantially all of the cost of gas purchased for utility operations is recovered from our customers through purchased gas adjustment mechanisms. However, our utility operations have commodity price risk exposure to fluctuations in spot natural gas prices related to purchases for sales to our non-regulated energy services customers at fixed prices.

For our utility segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a hypothetical 10 percent increase in the portion of our gas cost related to fixed-price non-regulated sales. Based on these projected non-regulated gas sales, a hypothetical 10 percent increase in fixed prices based upon the September 30, 2006 three month market strip, would increase our purchased gas cost by approximately $2.3 million in fiscal 2007.

Natural gas marketing and pipeline and storage segments

Our natural gas marketing segment is also exposed to risks associated with changes in the market price of natural gas. For our natural gas marketing segment, we use a sensitivity analysis to estimate commodity price risk. For purposes of this analysis, we estimate commodity price risk by applying a $0.50 change in the forward NYMEX price to our net open position (including existing storage and related financial contracts) at the end of each period. Based on AEH's net open position (including existing storage and related financial contracts) at September 30, 2006 of 0.2 Bcf, a $0.50 change in the forward NYMEX price would have had less than a $0.1 million impact on our consolidated net income.

Changes in the difference between the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) can result in volatility in our reported net income; but, over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges. Based upon our net physical position at September 30, 2006 and assuming our hedges would still qualify as highly effective, a $0.50 change in the difference between the Gas Daily and NYMEX indices would impact our reported net income by approximately $5.0 million.

Additionally, these changes could cause us to recognize a risk management liability, which would require us to place cash into an escrow account to collateralize this liability position. This, in turn, would reduce the amount of cash we would have on hand to fund our working capital needs. Because we recognized risk management liabilities as of September 30, 2006, we placed $35.6 million in escrow to collateralize these liabilities.

Interest Rate Risk

Our earnings are exposed to changes in short-term interest rates associated with our short-term commercial paper program and other short-term borrowings. We use a sensitivity analysis to estimate our short-term interest rate risk. For purposes of this analysis, we estimate our short-term interest rate risk as the difference between our actual interest expense for the period and estimated interest expense for the period assuming a hypothetical average one percent increase in the interest rates associated with our short-term borrowings. Had interest rates associated with our short-term borrowings increased by an average of one percent, our interest expense would have increased by approximately $3.6 million during 2006.

We also assess market risk for our fixed and floating rate long-term obligations. We estimate market risk for our long-term obligations as the potential increase in fair value resulting from a hypothetical one percent decrease in interest rates associated with these debt instruments. Fair value is estimated using a discounted cash flow analysis. Assuming this one percent hypothetical decrease, the fair value of our long-term obligations would have increased by approximately $143.3 million.

As of September 30, 2006, we were not engaged in other activities that would cause exposure to the risk of material earnings or cash flow loss due to changes in interest rates or market commodity prices.

ITEM 8. *Financial Statements and Supplementary Data*

Index to financial statements and financial statement schedule:

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All other financial statement schedules are omitted because the required information is not present, or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements and accompanying notes thereto.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON CONSOLIDATED FINANCIAL STATEMENTS

The Board of Directors
Atmos Energy Corporation

We have audited the accompanying consolidated balance sheets of Atmos Energy Corporation as of September 30, 2006 and 2005, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2006. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Atmos Energy Corporation at September 30, 2006 and 2005, and the consolidated results of its operations and its cash flows for each of the three years in the period ended September 30, 2006, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the financial statements taken as a whole, presents fairly, in all material respects, the financial information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Atmos Energy Corporation's internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 20, 2006 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Dallas, Texas
November 20, 2006

ATMOS ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30	
	2006	2005
	(In thousands, except share data)	
ASSETS		
Property, plant and equipment	$5,026,478	$4,631,684
Construction in progress	74,830	133,926
	5,101,308	4,765,610
Less accumulated depreciation and amortization	1,472,152	1,391,243
Net property, plant and equipment	3,629,156	3,374,367
Current assets		
Cash and cash equivalents	75,815	40,116
Cash held on deposit in margin account	35,647	80,956
Accounts receivable, less allowance for doubtful accounts of $13,686 in 2006 and $15,613 in 2005	374,629	454,313
Gas stored underground	461,502	450,807
Other current assets	169,952	238,238
Total current assets	1,117,545	1,264,430
Goodwill and intangible assets	738,521	737,787
Deferred charges and other assets	234,325	276,943
	$5,719,547	$5,653,527
CAPITALIZATION AND LIABILITIES		
Shareholders' equity		
Common stock, no par value (stated at $.005 per share); 200,000,000 shares authorized; issued and outstanding: 2006 — 81,739,516 shares, 2005 — 80,539,401 shares	$ 409	$ 403
Additional paid-in capital	1,467,240	1,426,523
Accumulated other comprehensive loss	(43,850)	(3,341)
Retained earnings	224,299	178,837
Shareholders' equity	1,648,098	1,602,422
Long-term debt	2,180,362	2,183,104
Total capitalization	3,828,460	3,785,526
Commitments and contingencies		
Current liabilities		
Accounts payable and accrued liabilities	345,108	461,314
Other current liabilities	388,451	503,368
Short-term debt	382,416	144,809
Current maturities of long-term debt	3,186	3,264
Total current liabilities	1,119,161	1,112,755
Deferred income taxes	306,172	292,207
Regulatory cost of removal obligation	261,376	263,424
Deferred credits and other liabilities	204,378	199,615
	$5,719,547	$5,653,527

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF INCOME

	Year Ended September 30		
	2006	2005	2004
	(In thousands, except per share data)		
Operating revenues			
Utility segment	$3,650,591	$3,103,140	$1,637,728
Natural gas marketing segment	3,156,524	2,106,278	1,618,602
Pipeline and storage segment	160,567	153,289	19,758
Other nonutility segment	5,898	5,302	3,393
Intersegment eliminations	(821,217)	(406,136)	(359,444)
	6,152,363	4,961,873	2,920,037
Purchased gas cost			
Utility segment	2,725,534	2,195,774	1,134,594
Natural gas marketing segment	3,025,897	2,044,305	1,571,971
Pipeline and storage segment	838	6,811	9,383
Other nonutility segment	—	—	—
Intersegment eliminations	(816,476)	(402,654)	(358,102)
	4,935,793	3,844,236	2,357,846
Gross profit	1,216,570	1,117,637	562,191
Operating expenses			
Operation and maintenance	433,418	416,281	214,470
Depreciation and amortization	185,596	178,005	96,647
Taxes, other than income	191,993	174,696	57,379
Impairment of long-lived assets	22,947	—	—
Total operating expenses	833,954	768,982	368,496
Operating income	382,616	348,655	193,695
Miscellaneous income	881	2,021	9,507
Interest charges	146,607	132,658	65,437
Income before income taxes	236,890	218,018	137,765
Income tax expense	89,153	82,233	51,538
Net income	$ 147,737	$ 135,785	$ 86,227
Per share data			
Basic net income per share	$ 1.83	$ 1.73	$ 1.60
Diluted net income per share	$ 1.82	$ 1.72	$ 1.58
Weighted average shares outstanding:			
Basic	80,731	78,508	54,021
Diluted	81,390	79,012	54,416

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Loss	Retained Earnings	Total
	Number of Shares	Stated Value				
	(In thousands, except share data)					
Balance, September 30, 2003	51,475,785	$257	$ 736,180	$ (1,459)	$ 122,539	$ 857,517
Comprehensive income:						
Net income	—	—	—	—	86,227	86,227
Unrealized holding gains on investments, net	—	—	—	615	—	615
Treasury lock agreements, net	—	—	—	(21,268)	—	(21,268)
Cash flow hedges, net	—	—	—	7,583	—	7,583
Total comprehensive income						73,157
Cash dividends ($1.22 per share)	—	—	—	—	(66,736)	(66,736)
Common stock issued:						
Public offering	9,939,393	50	235,419	—	—	235,469
Direct stock purchase plan	556,856	3	13,726	—	—	13,729
Retirement savings plan	320,313	2	8,300	—	—	8,302
1998 Long-term incentive plan	498,230	2	11,848	—	—	11,850
Long-term stock plan for Mid-States Division	6,000	—	94	—	—	94
Outside directors stock-for-fee plan	3,133	—	77	—	—	77
Balance, September 30, 2004	62,799,710	314	1,005,644	(14,529)	142,030	1,133,459
Comprehensive income:						
Net income	—	—	—	—	135,785	135,785
Unrealized holding gains on investments, net	—	—	—	1,528	—	1,528
Treasury lock agreements, net	—	—	—	(2,714)	—	(2,714)
Cash flow hedges, net	—	—	—	12,374	—	12,374
Total comprehensive income						146,973
Cash dividends ($1.24 per share)	—	—	—	—	(98,978)	(98,978)
Common stock issued:						
Public offering	16,100,000	80	381,271	—	—	381,351
Direct stock purchase plan	450,212	3	12,486	—	—	12,489
Retirement savings plan	441,350	2	11,767	—	—	11,769
1998 Long-term incentive plan	745,788	4	14,116	—	—	14,120
Stock-based compensation	—	—	1,175	—	—	1,175
Outside directors stock-for-fee plan	2,341	—	64	—	—	64
Balance, September 30, 2005	80,539,401	403	1,426,523	(3,341)	178,837	1,602,422
Comprehensive income:						
Net income	—	—	—	—	147,737	147,737
Unrealized holding gains on investments, net	—	—	—	882	—	882
Treasury lock agreements, net	—	—	—	3,442	—	3,442
Cash flow hedges, net	—	—	—	(44,833)	—	(44,833)
Total comprehensive income						107,228
Cash dividends ($1.26 per share)	—	—	—	—	(102,275)	(102,275)
Common stock issued:						
Direct stock purchase plan	387,833	2	10,391	—	—	10,393
Retirement savings plan	442,635	2	11,918	—	—	11,920
1998 Long-term incentive plan	366,905	2	8,976	—	—	8,978
Long-term stock plan for Mid-States Division	300	—	5	—	—	5
Stock-based compensation	—	—	9,361	—	—	9,361
Outside directors stock-for-fee plan	2,442	—	66	—	—	66
Balance, September 30, 2006	81,739,516	$409	$1,467,240	$(43,850)	$ 224,299	$1,648,098

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2006	2005	2004
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 147,737	$ 135,785	$ 86,227
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sales of assets	—	—	(6,700)
Impairment of long-lived assets	22,947	—	—
Depreciation and amortization:			
Charged to depreciation and amortization	185,596	178,005	96,647
Charged to other accounts	371	791	1,465
Deferred income taxes	86,178	12,669	36,997
Other	18,480	11,522	(1,772)
Changes in assets and liabilities:			
(Increase) decrease in cash held on deposit in margin account	45,309	(80,956)	17,903
(Increase) decrease in accounts receivable	78,407	(166,692)	2,158
Increase in gas stored underground	(10,695)	(112,796)	(31,030)
Increase in other current assets	(52,449)	(56,828)	(9,233)
Decrease in deferred charges and other assets	28,614	30,059	17,178
Increase (decrease) in accounts payable and accrued liabilities	(116,060)	224,375	4,586
Increase (decrease) in other current liabilities	(113,977)	218,715	48,877
Increase (decrease) in deferred credits and other liabilities	(9,009)	(7,705)	7,431
Net cash provided by operating activities	311,449	386,944	270,734
CASH FLOWS USED IN INVESTING ACTIVITIES			
Capital expenditures	(425,324)	(333,183)	(190,285)
Acquisitions, net of cash received	—	(1,916,696)	(1,957)
Proceeds from sales of assets	—	—	27,919
Other, net	(5,767)	(2,131)	(570)
Net cash used in investing activities	(431,091)	(2,252,010)	(164,893)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term debt	237,607	144,809	(118,595)
Net proceeds from issuance of long-term debt	—	1,385,847	5,000
Settlement of Treasury lock agreements	—	(43,770)	—
Repayment of long-term debt	(3,264)	(103,425)	(9,713)
Cash dividends paid	(102,275)	(98,978)	(66,736)
Issuance of common stock	23,273	37,183	34,715
Net proceeds from equity offering	—	381,584	235,737
Net cash provided by financing activities	155,341	1,703,250	80,408
Net increase (decrease) in cash and cash equivalents	35,699	(161,816)	186,249
Cash and cash equivalents at beginning of year	40,116	201,932	15,683
Cash and cash equivalents at end of year	$ 75,815	$ 40,116	$ 201,932

See accompanying notes to consolidated financial statements

ATMOS ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Nature of Business

Atmos Energy Corporation ("Atmos" or "the Company") and its subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. Through our natural gas utility business, we distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public-authority and industrial customers through our seven regulated natural gas utility divisions, in the service areas described below:

Division	Service Area
Atmos Energy Colorado-Kansas Division	Colorado, Kansas, Missouri[2]
Atmos Energy Kentucky Division[1]	Kentucky
Atmos Energy Louisiana Division	Louisiana
Atmos Energy Mid-States Division[1]	Georgia[2], Illinois[2], Iowa[2], Missouri[2], Tennessee, Virginia[2]
Atmos Energy Mid-Tex Division	Texas, including the Dallas/Fort Worth metropolitan area
Atmos Energy Mississippi Division	Mississippi
Atmos Energy West Texas Division	West Texas

[1] Effective October 1, 2006, the Kentucky and Mid-States Divisions were combined.

[2] Denotes locations where we have more limited service areas.

In addition, we transport natural gas for others through our distribution system. Our utility business is subject to federal and state regulation and/or regulation by local authorities in each of the states in which the utility divisions operate. Our shared-services division is located in Dallas, Texas, and our customer support centers are located in Amarillo and Waco, Texas.

Our nonutility businesses operate in 22 states and include our natural gas marketing operations, our pipeline and storage operations and our other nonutility operations. These operations are either organized under or managed by Atmos Energy Holdings, Inc. (AEH), which is wholly-owned by the Company.

Our natural gas marketing operations are managed by Atmos Energy Marketing, LLC (AEM), which is wholly-owned by AEH. AEM provides a variety of natural gas management services to municipalities, natural gas utility systems and industrial natural gas customers, primarily in the southeastern and midwestern states and to our Kentucky, Louisiana and Mid-States divisions. These services consist primarily of furnishing natural gas supplies at fixed and market-based prices, contract negotiation and administration, load forecasting, gas storage acquisition and management services, transportation services, peaking sales and balancing services, capacity utilization strategies and gas price hedging through the use of derivative instruments.

Our pipeline and storage operations consist of the operations of our Atmos Pipeline — Texas Division, a division of Atmos Energy Corporation, and of Atmos Pipeline and Storage, LLC (APS), which is wholly-owned by AEH. The Atmos Pipeline — Texas Division transports natural gas to the Atmos Energy Mid-Tex Division, transports natural gas to third parties and manages five underground storage reservoirs in Texas. Through APS, we own or have an interest in underground storage fields in Kentucky and Louisiana. We also use these storage facilities to reduce the need to contract for additional pipeline capacity to meet customer demand during peak periods.

Our other nonutility businesses consist primarily of the operations of Atmos Energy Services (AES), LLC and Atmos Power Systems, Inc., which are wholly-owned by AEH. Through AES, we provide natural gas management services to our utility operations, other than the Mid-Tex Division. These services, which began in April 2004, include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices. Through Atmos Power Systems, Inc., we have constructed electric peaking power-generating plants and associated facilities and have entered into agreements to lease these plants.

Prior to January 2004, United Cities Propane Gas, Inc., a wholly-owned subsidiary of AEH, owned an approximate 19 percent membership interest in U.S. Propane L.P. (USP), a joint venture formed in February 2000 with three other utility companies. Through our ownership in USP, we owned an approximate five percent indirect interest in Heritage Propane Partners, L.P. (Heritage). During 2004, we sold our interest in USP and Heritage. We received cash proceeds of $26.6 million and recorded a pretax book gain of $5.9 million with these transactions. We no longer have an interest in the propane industry.

2. Summary of Significant Accounting Policies

Principles of consolidation — The accompanying consolidated financial statements include the accounts of Atmos Energy Corporation and its wholly-owned subsidiaries. All material intercompany transactions have been eliminated.

Use of estimates — The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. The most significant estimates include the allowance for doubtful accounts, legal and environmental accruals, insurance accruals, pension and postretirement obligations, deferred income taxes, asset retirement obligation, impairment of long-lived assets, risk management and trading activities and the valuation of goodwill, indefinite-lived intangible assets and other long-lived assets. Actual results could differ from those estimates.

Regulation — Our utility operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. Our accounting policies recognize the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions. Regulated utility operations are accounted for in accordance with SFAS 71, *Accounting for the Effects of Certain Types of Regulation.* This statement requires cost-based, rate-regulated entities that meet certain criteria to reflect the authorized recovery of costs due to regulatory decisions in their financial statements. As a result, certain costs are permitted to be capitalized rather than expensed because they can be recovered through rates.

We record regulatory assets as a component of other current assets and deferred charges and other assets for costs that have been deferred for which future recovery through customer rates is considered probable. Regulatory liabilities are recorded either on the face of the balance sheet or as a component of current liabilities, deferred income taxes or deferred credits and other liabilities when it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. Significant regulatory assets and liabilities as of September 30, 2006 and 2005 included the following:

	September 30	
	2006	2005
	(In thousands)	
Regulatory assets:		
Merger and integration costs, net	$ 8,644	$ 9,150
Deferred gas costs	44,992	38,173
Environmental costs	1,234	1,357
Rate case costs	10,579	11,314
Deferred franchise fees	1,311	6,710
Other	9,055	9,313
	$ 75,815	$ 76,017
Regulatory liabilities:		
Deferred gas costs	$ 68,959	$134,048
Regulatory cost of removal obligation	276,490	274,989
Deferred income taxes, net	235	3,185
Other	10,825	8,084
	$356,509	$420,306

Currently authorized rates do not include a return on certain of our merger and integration costs; however, we recover the amortization of these costs. Merger and integration costs, net, are generally amortized on a straight-line basis over estimated useful lives ranging up to 20 years. During the fiscal years ended September 30, 2006, 2005 and 2004, we recognized $0.5 million, $2.3 million and $8.2 million in amortization expense related to these costs. Environmental costs have been deferred to be included in future rate filings in accordance with rulings received from various regulatory commissions.

As of September 30, 2006, our Mid-States Division had open rate cases in its Missouri and Tennessee service areas seeking rate increases of $3.4 million in each jurisdiction. The Tennessee rate was settled in October 2006 and resulted in a $6.1 million reduction in future annual revenues. We anticipate that the Missouri rate case will be finalized in February 2007. In addition, during 2006 our Mid-Tex Division filed a system-wide case seeking incremental annual revenues of approximately $60 million and several rate design changes. A ruling on this filing is anticipated by April 2007.

Revenue recognition — Sales of natural gas to our utility customers are billed on a monthly cycle basis; however, the billing cycle periods for certain classes of customers do not necessarily coincide with accounting periods used for financial reporting purposes. We follow the revenue accrual method of accounting for utility segment revenues whereby revenues applicable to gas delivered to customers, but not yet billed under the cycle billing method, are estimated and accrued and the related costs are charged to expense. Revenue is recognized in our pipeline and storage segment as the services are provided.

On occasion, we are permitted to implement new rates that have not been formally approved by our regulators and are subject to refund. As permitted by SFAS No. 71, we recognize this revenue and establish a

reserve for amounts that could be refunded based on our experience for the jurisdiction in which the rates were implemented.

Rates established by regulatory authorities are adjusted for increases and decreases in our purchased gas cost through purchased gas adjustment mechanisms. Purchased gas adjustment mechanisms provide gas utility companies a method of recovering purchased gas costs on an ongoing basis without filing a rate case to address all of the utility's non-gas costs. These mechanisms are commonly utilized when regulatory authorities recognize a particular type of expense, such as purchased gas costs, that (i) is subject to significant price fluctuations compared to the utility's other costs, (ii) represents a large component of the utility's cost of service and (iii) is generally outside the control of the gas utility. There is no gross profit generated through purchased gas adjustments, but they do provide a dollar-for-dollar offset to increases or decreases in utility gas costs. Although substantially all of our utility sales to our customers fluctuate with the cost of gas that we purchase, utility gross profit is generally not affected by fluctuations in the cost of gas due to the purchased gas adjustment mechanism. The effects of these purchased gas adjustment mechanisms are recorded as deferred gas costs on our balance sheet.

Energy trading contracts resulting in the delivery of a commodity where we are the principal in the transaction are recorded as natural gas marketing sales or purchases at the time of physical delivery. Realized gains and losses from the settlement of financial instruments that do not result in physical delivery related to our natural gas marketing energy trading contracts and unrealized gains and losses from changes in the market value of open contracts are included as a component of natural gas marketing revenues. For the years ended September 30, 2006, 2005 and 2004, we included unrealized gains (losses) on open contracts of $17.2 million, ($26.0) million and ($2.8) million as a component of natural gas marketing revenues.

Cash and cash equivalents — We consider all highly liquid investments with an initial or remaining maturity of three months or less to be cash equivalents.

Cash held on deposit in margin account — Cash held on deposit in margin account consists of deposits made to collateralize certain financial derivatives purchased in support of our risk management activities. Under the terms of these derivative contracts, when the fair value of financial instruments held represents a net liability position, we are required to deposit cash into a margin account.

Accounts receivable and allowance for doubtful accounts — Accounts receivable consist of natural gas sales to residential, commercial, industrial, municipal, agricultural and other customers. For the majority of our receivables, we establish an allowance for doubtful accounts based on our collections experience. On certain other receivables where we are aware of a specific customer's inability or reluctance to pay, we record an allowance for doubtful accounts against amounts due to reduce the net receivable balance to the amount we reasonably expect to collect. However, if circumstances change, our estimate of the recoverability of accounts receivable could be different. Circumstances which could affect our estimates include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible.

Gas stored underground — Our gas stored underground is comprised of natural gas injected into storage to support the winter season withdrawals for our utility operations and natural gas held by our natural gas marketing and other nonutility subsidiaries to conduct their operations. The average cost method is used for all our utility divisions, except for certain jurisdictions in the Mid-States Division, where it is valued on the first-in first-out method basis, in accordance with regulatory requirements. The average gas cost method is also used for our natural gas marketing segment and our Atmos Pipeline — Texas Division. Our Natural Gas Marketing segment utilizes the average cost method; however, most of this inventory is hedged and is therefore marked to market at the end of each month. Gas in storage that is retained as cushion gas to maintain reservoir pressure is classified as property, plant and equipment and is valued at cost.

Utility property, plant and equipment — Utility property, plant and equipment is stated at original cost, net of contributions in aid of construction. The cost of additions includes direct construction costs, payroll related costs (taxes, pensions and other fringe benefits), administrative and general costs and an allowance for funds used during construction. The allowance for funds used during construction represents the estimated cost of funds used to finance the construction of major projects and are capitalized in the rate base for ratemaking purposes when the completed projects are placed in service. Interest expense of $3.6 million, $2.5 million and $1.2 million was capitalized in 2006, 2005 and 2004.

Major renewals, including replacement pipe, and betterments that are recoverable under our regulatory rate base are capitalized while the costs of maintenance and repairs that are not recoverable through rates are charged to expense as incurred. The costs of large projects are accumulated in construction in progress until the project is completed. When the project is completed, tested and placed in service, the balance is transferred to the utility plant in service account included in the rate base and depreciation begins.

Utility property, plant and equipment is depreciated at various rates on a straight-line basis over the estimated useful lives of the assets. These rates are approved by our regulatory commissions and are comprised of two components, one based on average service life and one based on cost of removal. Accordingly, we recognize our cost of removal expense as a component of depreciation expense. The related cost of removal accrual is reflected as a regulatory liability on the consolidated balance sheet. At the time property, plant and equipment is retired, removal expenses less salvage, are charged to the regulatory cost of removal accrual. The composite depreciation rate was 3.9 percent, 4.0 percent and 3.8 percent for the years ended September 30, 2006, 2005 and 2004.

Nonutility property, plant and equipment — Nonutility property, plant and equipment is stated at cost. Depreciation is generally computed on the straight-line method for financial reporting purposes based upon estimated useful lives ranging from 8 to 38 years.

Asset retirement obligations — SFAS 143, *Accounting for Asset Retirement Obligations* and FIN 47, *Accounting for Conditional Asset Retirement Obligations*, which became effective for us September 30, 2006, require that we record a liability at fair value for an asset retirement obligation when the legal obligation to retire the asset has been incurred with an offsetting increase to the carrying value of the related asset. Accretion of the asset retirement obligation due to the passage of time is recorded as an operating expense.

As of September 30, 2006, we adopted the provisions of FIN 47. As a result of adopting FIN 47, we recorded an asset retirement obligation of $15.1 million associated with our distribution system. As retirement costs incurred by the distribution system are recovered from utility customers, this liability had previously been captured in our regulatory cost of removal liability. As a result of adopting FIN 47, we reclassified the $15.1 million from regulatory cost of removal liability to asset retirement obligation. In addition, we recorded $4.8 million of asset retirement costs that will be depreciated over the remaining life of the underlying associated asset lives. We believe we have a legal obligation to retire our storage wells. However, we have not recognized an asset retirement obligation associated with our storage wells because there is not sufficient industry history to reasonably estimate the fair value of this obligation. The adoption of FIN 47 did not have an impact to our results operations as the cost of removal expense has previously been recorded as described above. In accordance with the transition guidance of FIN 47, prior periods have not been restated; however, the asset retirement obligation as of September 30, 2005 would have been $14.6 million.

Impairment of long-lived assets — We periodically evaluate whether events or circumstances have occurred that indicate that other long-lived assets may not be recoverable or that the remaining useful life may warrant revision. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying

value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded.

During the fourth quarter of fiscal 2006, we determined that, as a result of declining irrigation sales primarily associated with our agricultural customers' shift from gas-powered pumps to electric pumps, the West Texas Division's irrigation assets would not be able to generate sufficient future cash flows from operations to recover the net investment in these assets. Therefore, we recorded a $22.9 million charge to impairment to write off the entire net book value. We will continue to operate these assets until we determine a plan for these assets as we are obligated to provide natural gas services to certain customers served by these assets.

Goodwill and intangible assets — We annually evaluate our goodwill balances for impairment during our second fiscal quarter or more frequently as impairment indicators arise. We use a present value technique based on discounted cash flows to estimate the fair value of our reporting units. These calculations are dependent on several subjective factors including the timing of future cash flows, future growth rates and the discount rate. An impairment charge is recognized if the carrying value of a reporting unit's goodwill exceeds its fair value.

Intangible assets are amortized over their useful lives of 10 years. These assets are reviewed for impairment as impairment indicators arise. When such events or circumstances are present, we assess the recoverability of long-lived assets by determining whether the carrying value will be recovered through the expected future cash flows. In the event the sum of the expected future cash flows resulting from the use of the asset is less than the carrying value of the asset, an impairment loss equal to the excess of the asset's carrying value over its fair value is recorded. To date, no impairment has been recognized.

Marketable securities — As of September 30, 2006 and 2005, all of our marketable securities were classified as available-for-sale securities based upon the criteria of SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities.* In accordance with that standard, these securities are reported at market value with unrealized gains and losses shown as a component of accumulated other comprehensive income (loss). We regularly evaluate the performance of these investments on a fund by fund basis for impairment, taking into consideration the fund's purpose, volatility and current returns. If a determination is made that a decline in fair value is other than temporary, the related fund is written down to its estimated fair value.

Derivatives and hedging activities — Our derivative and hedging activities are tailored to the segment to which they relate. We record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent other assets or liabilities based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Effective October 1, 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change did not have a material impact on our financial position on the date of adoption.

Utility Segment

In our utility segment, we use a combination of storage and financial derivatives to partially insulate us and our natural gas utility customers against gas price volatility during the winter heating season. The financial derivatives we use in our utility segment are accounted for under the mark-to-market method pursuant to SFAS 133, *Accounting for Derivative Instruments and Hedging Activities.* Changes in the valuation of these derivatives primarily result from changes in the valuation of the portfolio of contracts, maturity and settlement

of contracts and newly originated transactions. However, because the gains or losses of financial derivatives used in our utility segment will ultimately be recovered through our rates, current period changes in the assets and liabilities from these risk management activities are recorded as a component of deferred gas costs in accordance with SFAS 71. Accordingly, there is no earnings impact to our utility segment as a result of the use of financial derivatives. The changes in the assets and liabilities from risk management activities are recognized in purchased gas cost in the income statement when the related gain or loss is recovered through our rates.

Natural Gas Marketing Segment

Our natural gas marketing risk management activities are conducted through AEM. AEM is exposed to risks associated with changes in the market price of natural gas, and we manage our exposure to the risk of natural gas price changes through a combination of storage and financial derivatives, including futures, over-the-counter and exchange-traded options and swap contracts with counterparties. Option contracts provide the right, but not the requirement, to buy or sell the commodity at a fixed price. Swap contracts require receipt of payment for the commodity based on the difference between a fixed price and the market price on the settlement date. The use of these contracts is subject to our risk management policies, which are monitored for compliance daily.

We participate in transactions in which we combine the natural gas commodity and transportation costs to minimize our costs incurred to serve our customers. Additionally, we engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at favorable prices to lock in gross profit margins. Through the use of transportation and storage services and derivatives, we are able to capture gross profit margin through the arbitrage of pricing differences in various locations and by recognizing pricing differences that occur over time.

Under SFAS 133, natural gas inventory is designated as the hedged item in a fair-value hedge and is marked to market at the end of each month with changes in fair value recognized as unrealized gains and losses in revenue in the period of change. Effective October 1, 2005, we changed the index used to value our physical natural gas from Inside FERC to Gas Daily to better reflect the prices of our physical commodity. This change had no material impact on our financial position on the date of adoption. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas and deliver it out of the storage facility.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The difference in the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of storage gas inventory will be offset by gains and losses on the fair-value hedges, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change. When evaluating effectiveness, we exclude the differential between the spot price used to value our physical inventory and the forward price used to value the financial hedges designated against our physical inventory.

Similar to our inventory position, we attempt to mitigate substantially all of the commodity price risk associated with our fixed-price contracts with minimum volume requirements through the use of various offsetting derivatives. Prior to April 1, 2004, these derivatives were not designated as hedges under SFAS 133 because they naturally locked in the economic gross profit margin at the time we entered into the contract. The fixed-price forward and offsetting derivative contracts were marked to market each month with changes in

fair value recognized as unrealized gains and losses recorded in revenue in our consolidated statement of income. The unrealized gains and losses were realized as a component of revenue in the period in which we fulfilled the requirements of the fixed-price contract and the derivatives were settled. To the extent that the unrealized gains and losses of the fixed-price forward contracts and the offsetting derivatives did not offset exactly, our earnings experienced some volatility. At delivery, the gains and losses on the fixed-price contracts were offset by gains and losses on the derivatives, resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

Effective April 2004, we elected to treat our fixed-price forward contracts as normal purchases and sales. As a result, we ceased marking the fixed-price forward contracts to market. We have designated the offsetting derivative contracts as cash flow hedges of anticipated transactions. As a result of this change, unrealized gains and losses on these open derivative contracts are now recorded as a component of accumulated other comprehensive income and are recognized in earnings as a component of revenue when the hedged volumes are sold. In addition, we continually manage our positions to optimize value as market conditions and other circumstances change.

Additionally, we utilize storage swaps and futures to capture additional storage arbitrage opportunities that arise subsequent to the execution of the original fair value hedge associated with our physical natural gas inventory, basis swaps to insulate and protect the economic value of our fixed price and storage books and various over-the-counter and exchange-traded options. Although the purpose of these instruments is to either reduce basis or other risks or lock in arbitrage opportunities, these derivative instruments have not been designated as hedges. Accordingly, these derivative instruments are recorded at fair value with all changes in fair value included in revenue of our natural gas marketing segment.

In our natural gas marketing segment, hedge ineffectiveness arising from natural gas market price differences between the locations of the hedged inventory and the delivery location specified in the hedge instruments (referred to as basis ineffectiveness) for our fair value hedges resulted in an unrealized gain of $15.5 million for the year ended September 30, 2006 compared with an unrealized loss of $1.7 million and $0.6 million for the years ended September 30, 2005 and 2004. Basis ineffectiveness for our cash flow hedges resulted in an unrealized gain of approximately $20.0 million for the year ended September 30, 2006 compared with an unrealized loss of approximately $3.7 million and $0.5 million for the years ended September 30, 2005 and 2004. Hedge ineffectiveness arising from the timing of the settlement of physical contracts and the settlement of the related fair value hedge resulted in an unrealized gain of approximately $4.4 million and $0.5 million for the years ended September 30, 2006 and 2004 and an unrealized loss of approximately $2.2 million for the year ended September 30, 2005. The increased ineffectiveness is due to the high level of market volatility experienced in 2006.

Additionally, we have a policy which allows for the use of master netting agreements with significant counterparties that allow us to offset gains and losses arising from derivative instruments that may be settled in cash and/or gains and losses arising from derivative instruments that may be settled with the physical commodity. Assets and liabilities from risk management activities, as well as accounts receivable and payable, reflect the master netting agreements in place.

Pipeline and Storage Segment

Similar to AEM, Atmos Pipeline and Storage, LLC has designated its natural gas inventory as the hedged item in a fair-value hedge. The inventory is marked to market at the end of each month based upon Gas Daily index. Costs to store the gas are recognized in the period the costs are incurred. We recognize revenue and the carrying value of the inventory as an associated purchased gas cost in our consolidated statement of income when we sell the gas.

Derivatives associated with our natural gas inventory are marked to market each month based upon the NYMEX price with changes in fair value recognized as unrealized gains and losses in the period of change. The difference in the indices used to mark to market our physical inventory (Gas Daily) and the related fair-value hedge (NYMEX) is reported as a component of revenue and can result in volatility in our reported net income. Over time, gains and losses on the sale of natural gas inventory should be offset by gains and losses on the fair-value hedges; resulting in the realization of the economic gross profit margin we anticipated at the time we structured the original transaction.

In our pipeline and storage segment, actual hedge ineffectiveness arising from the timing of settlement of physical contracts and the settlement of the derivative instruments resulted in a loss of approximately $4.7 million for the year ended September 30, 2006, a gain of approximately $5.2 million for the year ended September 30, 2005 and a loss of less than $0.1 million for the year ended September 30, 2004.

Treasury Activities

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the anticipated issuance of $875 million of long-term debt. We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury lock agreements are recorded as a component of accumulated other comprehensive income. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation is being recognized as a component of interest expense over a five year period from the date of settlement, and the remaining amount, approximately $32.2 million, is being recognized as a component of interest expense over a ten year period from the date of settlement.

The fair value of our financial derivatives is determined through a combination of prices actively quoted on national exchanges, prices provided by other external sources and prices based on models and other valuation methods. Changes in the valuation of our financial derivatives primarily result from changes in market prices, the valuation of the portfolio of our contracts, maturity and settlement of these contracts and newly originated transactions, each of which directly affect the estimated fair value of our derivatives. We believe the market prices and models used to value these derivatives represent the best information available with respect to closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. Values are adjusted to reflect the potential impact of an orderly liquidation of our positions over a reasonable period of time under present market conditions.

Pension and other postretirement plans — Pension and other postretirement plan costs and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and current demographic and actuarial mortality data. We review the estimates and assumptions underlying our pension and other postretirement plan costs and liabilities annually based upon a June 30 measurement date. The assumed discount rate and the expected return are the assumptions that generally have the most significant impact on our pension costs and liabilities. The assumed discount rate, the assumed health care cost trend rate and assumed rates of retirement generally have the most significant impact on our postretirement plan costs and liabilities.

The discount rate is utilized principally in calculating the actuarial present value of our pension and postretirement obligation and net pension and postretirement cost. When establishing our discount rate, we consider high quality corporate bond rates based on Moody's Aa bond index, changes in those rates from the prior year and the implied discount rate that is derived from matching our projected benefit disbursements with a high quality corporate bond spot rate curve.

The expected long-term rate of return on assets is utilized in calculating the expected return on plan assets component of the annual pension and postretirement plan cost. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making final determination of our expected rate of return on assets. To the extent the actual rate of return on assets realized over the course of a year is greater than or less than the assumed rate, that year's annual pension or postretirement plan cost is not affected. Rather, this gain or loss reduces or increases future pension or postretirement plan cost over a period of approximately ten to twelve years.

We estimate the assumed health care cost trend rate used in determining our postretirement net cost based upon our actual health care cost experience, the effects of recently enacted legislation and general economic conditions. Our assumed rate of retirement is estimated based upon our annual review of our participant census information as of the measurement date.

Income taxes — Income taxes are provided based on the liability method, which results in income tax assets and liabilities arising from temporary differences. Temporary differences are differences between the tax bases of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The liability method requires the effect of tax rate changes on current and accumulated deferred income taxes to be reflected in the period in which the rate change was enacted. The liability method also requires that deferred tax assets be reduced by a valuation allowance unless it is more likely than not that the assets will be realized.

Stock-based compensation plans — We maintain the 1998 Long-Term Incentive Plan that provides for the granting of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to officers, division presidents and other key employees. Non-employee directors are also eligible to receive stock-based compensation under the 1998 Long-Term Incentive Plan. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire our common stock.

On October 1, 2005, the Company adopted SFAS 123 (revised), *Share-Based Payment* (SFAS 123(R)). This standard revises SFAS 123, *Accounting for Stock-Based Compensation* and supersedes Accounting Principles Board (APB) Opinion 25, *Accounting for Stock Issued to Employees.* Under SFAS 123(R), the Company is required to measure the cost of employee services received in exchange for stock options and similar awards based on the grant-date fair value of the award and recognize this cost in the income statement over the period during which an employee is required to provide service in exchange for the award.

We adopted SFAS 123(R) using the modified prospective method. Under this transition method, stock-based compensation expense for the year ended September 30, 2006 included: (i) compensation expense for all stock-based compensation awards granted prior to, but not yet vested as of October 1, 2005, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123; and (ii) compensation expense for all stock-based compensation awards granted subsequent to October 1, 2005, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). We recognize compensation expense on a straight-line basis over the requisite service period of the award. The impact of adoption on total stock-based compensation expense included in our statement of income for the year ended September 30, 2006 was $0.4 million and was recorded as a component of operation and maintenance expense. In accordance with the modified prospective method, financial results for prior periods have not been restated.

Prior to October 1, 2005, we accounted for these plans under the intrinsic-value method described in APB Opinion 25, as permitted by SFAS 123. Under this method, no compensation cost for stock options was recognized for stock-option awards granted at or above fair-market value. Awards of restricted stock were

valued at the market price of the Company's common stock on the date of grant. The unearned compensation was amortized as a component of operation and maintenance expense over the vesting period of the restricted stock.

Total stock-based compensation expense for the year ended September 30, 2006 was $9.4 million as compared to $3.9 million and $1.6 million for the years ended September 30, 2005 and 2004. Had compensation expense for our stock-based awards been recognized as prescribed by SFAS 123, our net income and earnings per share for the years ended September 30, 2005 and 2004 would have been impacted as shown in the following table:

	Year Ended September 30	
	2005	2004
	(In thousands, except per share data)	
Net income — as reported	$135,785	$86,227
Restricted stock compensation expense included in income, net of tax	2,431	978
Total stock-based employee compensation expense determined under fair-value- based method for all awards, net of taxes	(3,161)	(2,092)
Net income — pro forma	$135,055	$85,113
Earnings per share:		
Basic earnings per share — as reported	$ 1.73	$ 1.60
Basic earnings per share — pro forma	$ 1.72	$ 1.57
Diluted earnings per share — as reported	$ 1.72	$ 1.58
Diluted earnings per share — pro forma	$ 1.71	$ 1.56

Accumulated other comprehensive loss — Accumulated other comprehensive loss, net of tax, as of September 30, 2006 and 2005 consisted of the following unrealized gains (losses):

	September 30	
	2006	2005
	(In thousands)	
Unrealized holding gains on investments	$ 1,566	$ 684
Treasury lock agreements	(20,540)	(23,982)
Cash flow hedges	(24,876)	19,957
	$(43,850)	$ (3,341)

Recent accounting pronouncements — In February 2006, the FASB issued SFAS 155, *Accounting for Certain Hybrid Financial Instruments*, which amends SFAS 133, *Accounting for Derivative Instruments and Hedging Activities* and SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* SFAS 155 (a) permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, (b) clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS 133, (c) establishes a requirement to evaluate interests in securitized financial assets to identify interests that are freestanding derivatives or that are hybrid financial instruments that contain an embedded derivative requiring bifurcation, (d) clarifies that concentrations of credit risk in the form of subordination are not embedded derivatives and (e) amends SFAS 140 to eliminate the prohibition on a qualifying special-purpose entity from holding a derivative financial instrument that pertains to a beneficial interest other than another derivative financial instrument. SFAS 155 is effective for

all financial instruments acquired or issued by us after October 1, 2006 and the adoption of this standard is not expected to have a material impact on our financial position, results of operations and cash flows.

In March 2006, the FASB issued SFAS 156, *Accounting for Servicing Financial Assets*, which amends SFAS 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities.* SFAS 156 (a) revises guidance on when a servicing asset and servicing liability should be recognized, (b) requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value, if practicable, (c) permits an entity to choose to measure servicing assets and servicing liabilities under the amortization method or fair value measurement method, (d) at initial adoption, permits a one-time reclassification of available-for-sale securities to trading securities by entities with recognized servicing rights, without calling into question the treatment of other available-for-sale securities under SFAS 115, provided that the available-for-sale securities are identified as offsetting the exposure to changes in the fair value of servicing assets or liabilities that the servicer elects to subsequently measure at fair value and (e) requires separate presentation of servicing assets and servicing liabilities subsequently measured at fair value in the statement of financial position and additional footnote disclosure. We will be required to apply the provisions of SFAS 156 beginning October 1, 2006 and such application is expected not to have a material impact on our financial position, results of operations and cash flows.

In June 2006, the Emerging Issues Task Force (EITF) ratified EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation).* The EITF reached a consensus that the scope of this issue includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include sales, use, value added and some excise taxes. The EITF also reached a consensus that entities may present these taxes on either a gross or net basis. If the taxes are significant, an entity should disclose its policy of presenting taxes and the amounts of taxes that are recognized on a gross basis in interim and annual financial statements. We will be required to apply the provisions of EITF 06-3 beginning January 1, 2007. We are currently evaluating the impact this standard may have on our results of operations.

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes by establishing standards for measurement and recognition in financial statements of positions taken by an entity in its income tax returns. This interpretation also provides guidance on de-recognition of income tax assets and liabilities, classification of current and deferred income tax assets and liabilities, accounting for interest and penalties, accounting for income taxes in interim periods and income tax disclosures. We will be required to apply the provisions of FIN 48 beginning October 1, 2007. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS 157, *Fair Value Measurements.* SFAS 157 defines fair value, establishes a framework for measuring fair value and enhances disclosures about fair value measurements required under other accounting pronouncements but does not change existing guidance as to whether or not an instrument is carried at fair value. We will be required to apply the provisions of SFAS 157 beginning October 1, 2008. We are currently evaluating the impact this standard may have on our financial position, results of operations and cash flows.

In September 2006, the FASB issued SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R).* The new standard makes a significant change to the existing rules by requiring recognition in the balance sheet of the overfunded or underfunded positions of defined benefit pension and other postretirement plans, along with a corresponding noncash, after-tax adjustment to stockholders' equity. Additionally, this standard requires that the measurement date must correspond to the fiscal year end balance sheet date. This standard does not change how net periodic pension and postretirement cost or the projected benefit obligation is determined. The balance sheet recognition

guidance of this standard will be effective for fiscal 2007 and the measurement date provisions of this guidance can be adopted as late as fiscal 2008 for our company.

3. Acquisitions

TXU Gas Company

In October 2004, we completed our acquisition of the natural gas distribution and pipeline operations of TXU Gas Company. The purchase price for the TXU Gas acquisition was approximately $1.9 billion (after closing adjustments and before transaction costs and expenses), which we paid in cash. We did not assume any indebtedness of TXU Gas in connection with the acquisition. The purchase was accounted for as an asset purchase. We funded the purchase price for the TXU Gas acquisition with approximately $235.7 million in net proceeds from our offering of approximately 9.9 million shares of common stock, which we completed in July 2004, and approximately $1.7 billion in net proceeds from our issuance in October 2004 of commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into in September 2004 to provide bridge financing for the TXU Gas acquisition. In October 2004, we paid off the outstanding commercial paper used to fund the acquisition through the issuance of senior unsecured notes in October 2004, which generated net proceeds of approximately $1.39 billion, and the sale of 16.1 million shares of common stock in October 2004, which generated net proceeds of $381.6 million.

The following table summarizes the fair values of the assets acquired and liabilities assumed on October 1, 2004 (in thousands):

Cash purchase price	$1,908,999
Transaction costs and expenses	7,697
Total purchase price	$1,916,696
Net property, plant and equipment	$1,471,643
Accounts receivable	75,811
Gas stored underground	137,877
Other current assets	22,094
Goodwill	493,603
Deferred charges and other assets	42,069
Deferred income taxes	7,925
Accounts payable and accrued liabilities	(51,644)
Other current liabilities	(77,756)
Regulatory cost of removal obligation	(138,991)
Deferred credits and other liabilities	(65,935)
Total	$1,916,696

The sale of the TXU Gas operations was held through a competitive bid process. We believe the resulting goodwill is recoverable given the expected synergies we can achieve as a result of the TXU Gas acquisition. To that end, the TXU Gas acquisition significantly expands our existing utility operations in Texas. The North Texas operations of TXU Gas bridge our geographic operations between our existing utility operations in West Texas and Louisiana. TXU Gas's headquarters and service area are centered in Dallas, Texas, which is also the location of our corporate headquarters. Further, the addition of the regulated pipelines and storage operations in North Texas may create additional gas marketing and other opportunities for our non-regulated subsidiaries, which include gas marketing and storage operations. The goodwill generated in the acquisition is deductible for tax purposes.

At closing of the acquisition, TXU Gas and some of its affiliates entered into transitional services agreements with us to provide call center, meter reading, customer billing, collections, information reporting,

software, accounting, treasury, administrative and other services to the Mid-Tex Division. Some of these services were outsourced by TXU Gas to Capgemini Energy L.P. However, in November 2004, we entered into an agreement with Capgemini Energy L.P. whereby we assumed the operations of the Waco, Texas call center in April 2005 and purchased from Capgemini Energy L.P. all of the related call center assets in October 2005. The remaining transitional services agreements expired in September 2005 and were not renewed as we in-sourced all of these functions, effective October 2005.

The table below reflects the unaudited pro forma results of the Company and TXU Gas for the year ended September 30, 2004 as if the acquisition and related financing had taken place at the beginning of fiscal 2004 (in thousands, except per share data):

	Year Ended September 30, 2004
Operating revenue	$4,174,500
Net income	118,746
Net income per diluted share	$ 1.68

ComFurT Gas Inc.

Effective March 2004, we completed the acquisition of the natural gas distribution assets of ComFurT Gas Inc., a privately-held natural gas utility and propane distributor based in Buena Vista, Colorado, for approximately $2.0 million in cash. This company served approximately 1,800 natural gas utility customers. The acquisition enabled us to expand our contiguous service area in our Colorado-Kansas division. Unaudited pro forma results of the Company and ComFurT have not been presented as the acquisition was not material to our financial position or results of operations.

4. Goodwill and Intangible Assets

Goodwill and intangible assets were comprised of the following as of September 30, 2006 and 2005.

	September 30	
	2006	2005
	(In thousands)	
Goodwill	$735,369	$734,280
Intangible assets	3,152	3,507
Total	$738,521	$737,787

The following presents our goodwill balance allocated by segment and changes in the balance for the year ended September 30, 2006:

	Utility Segment	Natural Gas Marketing Segment	Pipeline and Storage Segment	Other Nonutility Segment	Total
			(In thousands)		
Balance as of September 30, 2005	$566,800	$24,282	$143,198	$—	$734,280
Deferred tax adjustments on prior acquisitions[1]	421	—	668	—	1,089
Balance as of September 30, 2006	$567,221	$24,282	$143,866	$—	$735,369

[1] During the preparation of the fiscal 2006 tax provision, we adjusted certain deferred taxes recorded in connection with a fiscal 2001 and a fiscal 2004 acquisitions which resulted in an increase to goodwill and net deferred tax liabilities of $1.1 million.

Information regarding our intangible assets is included in the following table. As of September 30, 2006 and 2005, we had no indefinite-lived intangible assets.

	Useful Life (Years)	September 30, 2006 Gross Carrying Amount	Accumulated Amortization	Net	September 30, 2005 Gross Carrying Amount	Accumulated Amortization	Net
		(In thousands)					
Customer contracts	10	$6,754	$(3,602)	$3,152	$6,521	$(3,014)	$3,507

The following table presents actual amortization expense recognized during 2006 and an estimate of future amortization expense based upon our intangible assets at September 30, 2006.

Amortization expense (in thousands):	
Actual for the fiscal year ending September 30, 2006	$588
Estimated for the fiscal year ending:	
September 30, 2007	608
September 30, 2008	608
September 30, 2009	608
September 30, 2010	608
September 30, 2011	608

5. Derivative Instruments and Hedging Activities

We conduct risk management activities through both our utility and natural gas marketing segments. These activities are described in more detail in Note 2. Also, as discussed in Note 2, we record our derivatives as a component of risk management assets and liabilities, which are classified as current or noncurrent based upon the anticipated settlement date of the underlying derivative. Our determination of the fair value of these derivative financial instruments reflects the estimated amounts that we would receive or pay to terminate or close the contracts at the reporting date, taking into account the current unrealized gains and losses on open contracts. In our determination of fair value, we consider various factors, including closing exchange and over-the-counter quotations, time value and volatility factors underlying the contracts. These risk management assets and liabilities are subject to continuing market risk until the underlying derivative contracts are settled.

The following table shows the fair values of our risk management assets and liabilities by segment at September 30, 2006 and 2005:

	Utility	Natural Gas Marketing	Total
		(In thousands)	
September 30, 2006:			
Assets from risk management activities, current	$ —	$ 12,553	$ 12,553
Assets from risk management activities, noncurrent	—	6,186	6,186
Liabilities from risk management activities, current	(27,209)	(3,460)	(30,669)
Liabilities from risk management activities, noncurrent	—	(276)	(276)
Net assets (liabilities)	$(27,209)	$ 15,003	$ (12,206)
September 30, 2005:			
Assets from risk management activities, current	$ 93,310	$ 14,603	$107,913
Assets from risk management activities, noncurrent	—	735	735
Liabilities from risk management activities, current	—	(61,920)	(61,920)
Liabilities from risk management activities, noncurrent	—	(15,316)	(15,316)
Net assets (liabilities)	$ 93,310	$(61,898)	$ 31,412

Utility Hedging Activities

We use a combination of storage, fixed physical contracts and fixed financial contracts to partially insulate us and our customers against gas price volatility during the winter heating season. For the 2005-2006 heating season, we hedged approximately 46 percent of our anticipated winter flowing gas requirements at a weighted average cost of approximately $9.06 per Mcf.

Our utility hedging activities also includes the fair value of our treasury lock agreements which are described in further detail below.

Nonutility Hedging Activities

For the year ended September 30, 2006, the change in the deferred hedging position in accumulated other comprehensive loss was attributable to decreases in future commodity prices relative to the commodity prices stipulated in the derivative contracts totaling $51.0 million and the recognition of $6.2 million in net deferred hedging losses in net income when the derivatives matured according to their terms. The net deferred hedging losses associated with open cash flow hedges remain subject to market price fluctuations until the positions are either settled under the terms of the hedge contracts or terminated prior to settlement. Substantially all of the deferred hedging loss as of September 30, 2006 is expected to be recognized in net income within the next fiscal year.

Under our risk management policies, we seek to match our financial derivative positions to our physical storage positions as well as our expected current and future sales and purchase obligations to maintain no open positions at the end of each trading day. The determination of our net open position as of any day, however, requires us to make assumptions as to future circumstances, including the use of gas by our customers in relation to our anticipated storage and market positions. Because the price risk associated with any net open position at the end of each day may increase if the assumptions are not realized, we review these assumptions as part of our daily monitoring activities. We can also be affected by intraday fluctuations of gas prices, since the price of natural gas purchased or sold for future delivery earlier in the day may not be hedged until later in the day. At times, limited net open positions related to our existing and anticipated commitments may occur.

At the close of business on September 30, 2006, AEH had a net open position (including existing storage) of 0.2 Bcf.

Treasury Activities

During fiscal 2004, we entered into four Treasury lock agreements to fix the Treasury yield component of the interest cost of financing associated with the-then anticipated issuance of $875 million of long-term debt subsequent to September 30, 2004. This long-term debt was issued in October 2004 and was used to repay a portion of the commercial paper used to fund the TXU Gas acquisition, as described in Note 3.

We designated these Treasury lock agreements as cash flow hedges of an anticipated transaction. Accordingly, to the extent effective, unrealized gains and losses associated with the Treasury locks were recorded as a component of accumulated other comprehensive loss. These Treasury lock agreements were settled in October 2004 with a net $43.8 million payment to the counterparties. Approximately $11.6 million of the $43.8 million obligation is being recognized as a component of interest expense over a five year period from the date of settlement, and the remaining amount, approximately $32.2 million, is being recognized as a component of interest expense over a ten year period from the date of settlement.

The following table presents our hedging transactions that were recorded to other comprehensive income (loss), net of taxes during the years ended September 30, 2006 and 2005.

	Year Ended September 30	
	2006	2005
	(In thousands)	
Increase (decrease) in fair value:		
Treasury lock agreements	$ —	$(5,869)
Forward commodity contracts	(51,014)	1,988
Recognition of (gains) losses in earnings due to settlements:		
Treasury lock agreements	3,442	3,155
Forward commodity contracts	6,181	10,386
Total other comprehensive income (loss) from hedging, net of tax[1]	$(41,391)	$ 9,660

[1] Utilizing an income tax rate of approximately 38 percent comprised of the effective rates in each taxing jurisdiction.

The following amounts, net of deferred taxes, represent the expected recognition into earnings for our derivative instruments, based upon the fair values of these derivatives as of September 30, 2006:

	Treasury Lock Agreements	Forward Contracts	Total
		(In thousands)	
2007	$ (3,442)	$(24,100)	$(27,542)
2008	(3,442)	(732)	(4,174)
2009	(3,442)	(38)	(3,480)
2010	(2,123)	(6)	(2,129)
2011	(2,003)	—	(2,003)
Thereafter	(6,088)	—	(6,088)
Total	$(20,540)	$(24,876)	$(45,416)

6. Debt

Long-term debt

Long-term debt at September 30, 2006 and 2005 consisted of the following:

	2006	2005
	(In thousands)	
Unsecured floating rate Senior Notes, due October 2007	$ 300,000	$ 300,000
Unsecured 4.00% Senior Notes, due 2009	400,000	400,000
Unsecured 7.375% Senior Notes, due 2011	350,000	350,000
Unsecured 10% Notes, due 2011	2,303	2,303
Unsecured 5.125% Senior Notes, due 2013	250,000	250,000
Unsecured 4.95% Senior Notes, due 2014	500,000	500,000
Unsecured 5.95% Senior Notes, due 2034	200,000	200,000
Medium term notes		
Series A, 1995-2, 6.27%, due 2010	10,000	10,000
Series A, 1995-1, 6.67%, due 2025	10,000	10,000
Unsecured 6.75% Debentures, due 2028	150,000	150,000
First Mortgage Bonds Series P, 10.43% due 2013	8,750	10,000
Rental property, propane and other term notes due in installments through 2013	5,825	7,839
Total long-term debt	2,186,878	2,190,142
Less:		
Original issue discount on unsecured senior notes and debentures	(3,330)	(3,774)
Current maturities	(3,186)	(3,264)
	$2,180,362	$2,183,104

In December 2001, we filed a registration statement with the Securities and Exchange Commission (SEC) to issue, from time to time, up to $600.0 million in new common stock and/or debt. The registration statement was declared effective by the SEC in January 2002. In July 2004, we sold 9.9 million shares of our common stock. We used the net proceeds from this offering, together with borrowings under a bridge financing facility to consummate the acquisition of TXU Gas operations and pay related fees and expenses. As a result of the offering, we exhausted the remaining availability under our December 2001 registration statement.

In August 2004, we filed another registration statement with the SEC, which was declared effective by the SEC in September 2004, under which we could issue, from time to time, up to $2.2 billion in new common stock and/or debt. In October 2004, we sold 16.1 million common shares, including the underwriters' exercise of their overallotment option, under the new registration statement, generating net proceeds of $382.5 million before other offering costs. Additionally, we issued senior unsecured debt under the registration statement consisting of $400 million of 4.00% Senior Notes due 2009, $500 million of 4.95% Senior Notes due 2014, $200 million of 5.95% Senior Notes due 2034 and $300 million of floating rate Senior Notes due 2007. The floating rate notes bear interest at a rate equal to the three-month LIBOR rate plus 0.375 percent per year. At September 30, 2006, the interest rate on our floating rate debt was 5.882 percent. The net proceeds from the sale of these senior notes were $1.39 billion.

The net proceeds from the October 2004 common stock and senior notes offerings, combined with the net proceeds from our July 2004 offering were used to pay off the $1.7 billion in outstanding commercial paper backstopped by a senior unsecured revolving credit agreement, which we entered into in September 2004 for

bridge financing for the TXU Gas acquisition. Also, as a result of this refinancing in October 2004, we canceled the senior unsecured revolving credit facility. After issuing the debt and equity in October 2004 we had approximately $401.5 million in availability remaining under the registration statement. However, we are no longer allowed to issue securities under that registration statement by applicable state regulatory commissions. See further discussion in the Liquidity section of Management's Discussion and Analysis.

In June 2005, we elected to utilize excess cash to repay $72.5 million in principal on five series of our First Mortgage Bonds prior to their scheduled maturity. In connection with the repayment, we paid a $25.0 million make-whole premium in accordance with the terms of the agreements and accrued interest of approximately $1.0 million. In accordance with regulatory requirements, the premium has been deferred and will be recognized over the remaining original lives of the First Mortgage Bonds that were repaid.

Short-term debt

At September 30, 2006 and 2005, there was $379.3 million and $129.9 million outstanding under our commercial paper program and $3.1 million and $14.9 million outstanding under our bank credit facilities. As of September 30, 2006, our commercial paper had maturities of less than three months, with interest rates ranging from 5.47 percent to 5.51 percent.

Credit facilities

We maintain both committed and uncommitted credit facilities. Borrowings under our uncommitted credit facilities are made on a when-and-as-needed basis at the discretion of the bank. Our credit capacity and the amount of unused borrowing capacity are affected by the seasonal nature of the natural gas business and our short-term borrowing requirements, which are typically highest during colder winter months. Our working capital needs can vary significantly due to changes in the price of natural gas charged by suppliers and the increased gas supplies required to meet customers' needs during periods of cold weather.

Committed credit facilities

As of September 30, 2006, we had three short-term committed revolving credit facilities totaling $918 million. The first facility is a three-year unsecured facility, expiring October 2008, for $600 million that bears interest at a base rate or at the LIBOR rate for the applicable interest period, plus from 0.40 percent to 1.00 percent, based on the Company's credit ratings, and serves as a backup liquidity facility for our $600 million commercial paper program. At September 30, 2006, there was $379.3 million outstanding under our commercial paper program.

We have a second unsecured facility in place which is a 364-day facility for $300 million that bears interest at a base rate or the LIBOR rate for the applicable interest period, plus from 0.30 percent to 0.75 percent, based on the Company's credit ratings. This facility expired in November 2006 and was renewed for one year with no material changes to its terms and pricing. At September 30, 2006, there were no borrowings under this facility.

We have a third unsecured facility in place for $18 million that bears interest at the Federal Funds rate plus 0.5 percent. This facility expired in March 2006 and was renewed for one year with no material changes to its terms and pricing. At September 30, 2006, there was $3.1 million outstanding under this facility.

The availability of funds under our credit facilities is subject to conditions specified in the respective credit agreements, all of which we currently satisfy. These conditions include our compliance with financial covenants and the continued accuracy of representations and warranties contained in these agreements. We are required by the financial covenants in our revolving credit facilities to maintain, at the end of each fiscal quarter, a ratio of total debt to total capitalization of no greater than 70 percent. At September 30, 2006, our

total-debt-to-total-capitalization ratio, as defined, was 63 percent. In addition, both the interest margin over the Eurodollar rate and the fee that we pay on unused amounts under our revolving credit facilities are subject to adjustment depending upon our credit ratings. The revolving credit facilities each contain the same limitation with respect to our total-debt to-total capitalization ratio.

Uncommitted credit facilities

In November 2005, AEM amended its $250 million uncommitted demand working capital credit facility to increase the amount of credit available from $250 million to a maximum of $580 million. In March 2006, AEM amended and extended this uncommitted demand working capital credit facility to March 2007.

Borrowings under the amended credit facility can be made either as revolving loans or offshore rate loans. Revolving loan borrowings will bear interest at a floating rate equal to a base rate (defined as the higher of 0.50 percent per annum above the Federal Funds rate or the lender's prime rate) plus 0.25 percent. Offshore rate loan borrowings will bear interest at a floating rate equal to a base rate based upon LIBOR for the applicable interest period, plus an applicable margin, ranging from 1.25 percent to 1.625 percent per annum, depending on the excess tangible net worth of AEM, as defined in the credit facility. Borrowings drawn down under letters of credit issued by the banks will bear interest at a floating rate equal to the base rate, as defined above, plus an applicable margin, which will range from 1.00 percent to 1.875 percent per annum, depending on the excess tangible net worth of AEM and whether the letters of credit are swap-related standby letters of credit.

AEM is required by the financial covenants in the credit facility to maintain a maximum ratio of total liabilities to tangible net worth of 5 to 1, along with minimum levels of net working capital ranging from $20 million to $120 million. Additionally, AEM must maintain a minimum tangible net worth ranging from $21 million to $121 million, and must not have a maximum cumulative loss from March 30, 2005 exceeding $4 million to $23 million, depending on the total amount of borrowing elected from time to time by AEM. At September 30, 2006, AEM's ratio of total liabilities to tangible net worth, as defined, was 1.24 to 1.

At September 30, 2006, there were no borrowings outstanding under this credit facility. However, at September 30, 2006, AEM letters of credit totaling $96.1 million had been issued under the facility, which reduced the amount available by a corresponding amount. The amount available under this credit facility is also limited by various covenants, including covenants based on working capital. Under the most restrictive covenant, the amount available to AEM under this credit facility was $53.9 million at September 30, 2006. This line of credit is collateralized by substantially all of the assets of AEM and is guaranteed by AEH.

We also have an unsecured short-term uncommitted credit line for $25 million that is used for working capital and letter-of-credit purposes. There were no borrowings under this uncommitted credit facility at September 30, 2006, but letters of credit reduced the amount available by $4.5 million. This uncommitted line is renewed or renegotiated at least annually with varying terms, and we pay no fee for the availability of the line. Borrowings under this line are made on a when-and-as-available basis at the discretion of the bank.

AEH, the parent company of AEM, has a $100 million intercompany uncommitted demand credit facility with the Company which bears interest at the One Month LIBOR plus 2.75 percent. This facility has been approved by our state regulators through December 31, 2006. At September 30, 2006, there were no borrowings outstanding under this credit facility. In July 2006, this facility was renewed for one year with no material changes to its terms.

In addition, AEM has a $120 million intercompany uncommitted demand credit facility with AEH for its nonutility business which bears interest at the One Month LIBOR plus 2.75 percent. Any outstanding amounts under this facility are subordinated to AEM's $580 million uncommitted demand credit facility described above. This facility is used to supplement AEM's $580 million credit facility. At September 30, 2006, there were no borrowings outstanding under this credit facility. In July 2006, this facility was renewed for one year with no material changes to its terms.

Debt Covenants

We have other covenants in addition to those described above. Our Series P First Mortgage Bonds contain provisions that allow us to prepay the outstanding balance in whole at any time, after November 2007, subject to a prepayment premium. The First Mortgage Bonds provide for certain cash flow requirements and restrictions on additional indebtedness, sale of assets and payment of dividends. Under the most restrictive of such covenants, cumulative cash dividends paid after December 31, 1985 may not exceed the sum of accumulated net income for periods after December 31, 1985 plus $9.0 million. At September 30, 2006 approximately $203.3 million of retained earnings was unrestricted with respect to the payment of dividends.

As of September 30, 2006, a portion of the Mid-States Division utility plant assets, totaling $394.2 million, was subject to a lien under the Indenture of Mortgage of the Series P First Mortgage Bonds.

We were in compliance with all of our debt covenants as of September 30, 2006. If we do not comply with our debt covenants, we may be required to repay our outstanding balances on demand, provide additional collateral or take other corrective actions. Our two public debt indentures relating to our senior notes and debentures, as well as both our revolving credit agreements, each contain a default provision that is triggered if outstanding indebtedness arising out of any other credit agreements in amounts ranging from in excess of $15 million to in excess of $100 million becomes due by acceleration or is not paid at maturity. In addition, AEM's credit agreement contains a cross-default provision whereby AEM would be in default if it defaults on other indebtedness, as defined, by at least $250 thousand in the aggregate. Additionally, this agreement contains a provision that would limit the amount of credit available if Atmos were downgraded below an S&P rating of BBB and a Moody's rating of Baa2.

Except as described above, we have no triggering events in our debt instruments that are tied to changes in specified credit ratings or stock price, nor have we entered into any transactions that would require us to issue equity based on our credit rating or other triggering events.

Based on the borrowing rates currently available to us for debt with similar terms and remaining average maturities, the fair value of long-term debt at September 30, 2006 and 2005 is estimated, using discounted cash flow analysis, to be $2,053.9 million and $2,078.3 million.

Maturities of long-term debt at September 30, 2006 were as follows (in thousands):

2007	$ 3,186
2008	303,831
2009	2,034
2010	401,381
2011	361,381
Thereafter	1,115,065
	$2,186,878

7. Shareholders' Equity

Stock Issuances

During the years ended September 30, 2006, 2005 and 2004 we issued 1,200,115, 17,739,691 and 11,323,925 shares of common stock.

In February 2005, our shareholders approved an amendment to our Articles of Incorporation to increase the number of authorized shares from 100 million to 200 million.

In October 2004, we completed the public offering of 16.1 million shares of our common stock including the underwriters' exercise of their overallotment option of 2.1 million shares. The offering was priced at $24.75 and generated net proceeds of approximately $381.6 million. We used the net proceeds from this offering, together with net proceeds of $235.7 million from a public offering we conducted in July 2004 and $1.39 billion received from the issuance of senior unsecured notes, to repay the $1.7 billion in outstanding commercial paper described in Note 3 and fund the remainder of the purchase price for the TXU Gas acquisition.

Shareholder Rights Plan

In November 1997, our Board of Directors declared a dividend distribution of one right for each outstanding share of our common stock to shareholders of record at the close of business on May 10, 1998. Each right entitles the registered holder to purchase from us a one-tenth share of our common stock at a purchase price of $8.00 per share, subject to adjustment. The description and terms of the rights are set forth in a rights agreement between us and the rights agent.

Subject to exceptions specified in the rights agreement, the rights will separate from our common stock and a distribution date will occur upon the earlier of:

- ten business days following a public announcement that a person or group of affiliated or associated persons has acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock, other than as a result of repurchases of stock by us or specified inadvertent actions by institutional or other shareholders;
- ten business days, or such later date as our Board of Directors shall determine, following the commencement of a tender offer or exchange offer that would result in a person or group having acquired, or obtained the right to acquire, beneficial ownership of 15 percent or more of the outstanding shares of our common stock; or
- ten business days after our Board of Directors shall declare any person to be an adverse person within the meaning of the rights plan.

The rights expire on May 10, 2008, unless extended prior thereto by our board of directors or earlier if redeemed by us. The rights will not have any voting rights. The exercise price payable and the number of shares of our common stock or other securities or property issuable upon exercise of the rights are subject to adjustment from time to time to prevent dilution. We issue rights when we issue our common stock until the rights have separated from the common stock. After the rights have separated from the common stock, we may issue additional rights if the board of directors deems such issuance to be necessary or appropriate. The rights have "anti-takeover" effects and may cause substantial dilution to a person or entity that attempts to acquire us on terms not approved by our board of directors except pursuant to an offer conditioned upon a substantial number of rights being acquired. The rights should not interfere with any merger or other business combination approved by our board of directors because, prior to the time that the rights become exercisable or transferable, we can redeem the rights at $.01 per right.

Other Agreements

In connection with our Mississippi Valley Gas Company acquisition in December 2002, we issued shares of common stock under an exemption from registration under the Securities Act of 1933, as amended. In the transaction, we entered into a registration rights agreement with the former stockholders of Mississippi Valley Gas Company that required us, on no more than two occasions, and with some limitations, to file a registration statement under the Securities Act within 60 days of their request for an offering designed to achieve a wide distribution of shares through underwriters selected by us. We also granted rights to these shareholders, subject to some limitations, to participate in future registered offerings of our securities until December 3, 2005. No

registration rights issued to the former stockholders of MVG, as discussed above, were exercised prior to the expiration of the registration rights agreement on December 3, 2005. The former stockholders of MVG also agreed, for up to five years from the closing of the acquisition, or until December 3, 2007, and with some exceptions, not to sell or transfer shares representing more than 1 percent of our total outstanding voting securities to any person or group or any shares to a person or group who would hold more than 9.9 percent of our total outstanding voting securities after the sale or transfer. This restriction, and other agreed restrictions on the ability of these shareholders to acquire additional shares, participate in proxy solicitations or act to seek control, may be deemed to have an "anti-takeover" effect.

8. Stock and Other Compensation Plans

Stock-Based Compensation Plans

1998 Long-Term Incentive Plan

In August 1998, the Board of Directors approved and adopted the 1998 Long-Term Incentive Plan, which became effective in October 1998 after approval by our shareholders. The Long-Term Incentive Plan is a comprehensive, long-term incentive compensation plan providing for discretionary awards of incentive stock options, non-qualified stock options, stock appreciation rights, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units to certain employees and non-employee directors of Atmos and its subsidiaries. The objectives of this plan include attracting and retaining the best personnel, providing for additional performance incentives and promoting our success by providing employees with the opportunity to acquire common stock. We are authorized to grant awards for up to a maximum of four million shares of common stock under this plan subject to certain adjustment provisions. As of September 30, 2006, non-qualified stock options, bonus stock, time-lapse restricted stock, performance-based restricted stock units and stock units had been issued under this plan, and 731,745 shares were available for future issuance. The option price of the stock options issued under this plan is equal to the market price of our stock at the date of grant. These stock options expire 10 years from the date of the grant and vest annually over a service period ranging from one to three years.

We used the Black-Scholes pricing model to estimate the fair value of each option granted with the following weighted average assumptions for 2006, 2005 and 2004:

	Year Ended September 30		
	2006	2005	2004
Valuation Assumptions[1]			
Expected Life *(years)*[2]	7	7	7
Interest rate[3]	4.6%	4.2%	4.3%
Volatility[4]	20.3%	21.3%	22.8%
Dividend yield	4.8%	4.8%	4.8%

(1) Beginning on the date of adoption of SFAS 123(R), forfeitures are estimated based on historical experience. Prior to the date of adoption, forfeitures were recorded as they occurred.

(2) The expected life of stock options is estimated based on historical experience.

(3) The interest rate is based on the U.S. Treasury constant maturity interest rate whose term is consistent with the expected life of the stock options.

(4) The volatility is estimated based on historical and current stock data for the Company.

A summary of activity for grants of stock options under the 1998 Long-Term Incentive Plan follows:

	2006		2005		2004	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding at beginning of year	964,704	$22.20	1,492,177	$22.10	1,827,310	$21.91
Granted	93,196	26.19	23,432	25.95	8,118	24.44
Exercised	(40,582)	22.21	(547,907)	22.08	(342,252)	20.91
Forfeited	(166)	21.23	(2,998)	22.81	(999)	22.49
Outstanding at end of year[1]	1,017,152	$22.57	964,704	$22.20	1,492,177	$22.10
Exercisable at end of year[2]	991,778	$22.48	798,574	$22.22	1,006,859	$22.23

(1) The weighted-average remaining contractual life for outstanding options was 5.4 years, 6.0 years, and 7.0 years for fiscal years 2006, 2005 and 2004. The aggregate intrinsic value of outstanding options was $3.7 million, $3.5 million and $5.4 million for fiscal years 2006, 2005 and 2004.

(2) The weighted-average remaining contractual life for exercisable options was 5.3 years, 5.7 years, and 6.5 years for fiscal years 2006, 2005 and 2004. The aggregate intrinsic value of exercisable options was $3.6 million, $2.9 million and $3.7 million for fiscal years 2006, 2005 and 2004.

Information about outstanding and exercisable options under the 1998 Long-Term Incentive Plan, as of September 30, 2006, follows:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number of Options	Weighted Average Remaining Contractual Life (In Years)	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
$15.65 to $20.24	64,833	3.4	$15.66	64,833	$15.66
$20.25 to $22.99	547,414	5.8	$21.87	547,414	$21.87
$23.00 to $26.19	404,905	5.1	$24.62	379,531	$24.53
$15.65 to $26.19	1,017,152	5.4	$22.57	991,778	$22.48

The stock options had a weighted average fair value per share on the date of grant of $3.74 in 2006, $3.69 in 2005 and $3.82 in 2004. Net cash proceeds from the exercise of stock options during the years ended September 30, 2006, 2005 and 2004 were $0.9 million, $12.1 million and $7.2 million. The associated income tax benefit from stock options exercised during the years ended September 30, 2006, 2005 and 2004 were less than $0.1 million, $1.3 million and $0.6 million. The total intrinsic value of options exercised during the years ended September 30, 2006, 2005 and 2004 were less than $0.1 million, $2.0 million and $1.2 million.

As of September 30, 2006, there was less than $0.1 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a weighted-average period of 1.3 years.

Restricted Stock Plans

As noted above, the 1998 Long-Term Incentive Plan provides for discretionary awards of restricted stock to help attract, retain and reward employees and non-employee directors of Atmos and its subsidiaries. Certain of these awards vest based upon the passage of time and other awards vest based upon the passage of time

and the achievement of specified performance targets. The associated expense is recognized ratably over the vesting period. The following summarizes information regarding the restricted stock plan:

	2006		2005		2004	
	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Number of Restricted Shares	Weighted Average Grant-Date Fair Value	Number of Restricted Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of year	592,490	$25.32	345,519	$23.72	107,837	$21.19
Granted	440,016	26.80	294,834	26.78	240,686	24.78
Vested	(265,546)	24.42	(36,106)	21.97	(2,175)	15.65
Forfeited	(20,184)	26.95	(11,757)	24.70	(829)	23.83
Nonvested at end of year	746,776	$26.49	592,490	$25.32	345,519	$23.72

As of September 30, 2006, there was $12.4 million of total unrecognized compensation cost related to nonvested restricted shares granted under the 1998 Long-Term Incentive Plan. That cost is expected to be recognized over a weighted-average period of 1.9 years. The fair value of restricted stock vested during the years ended September 30, 2006, 2005 and 2004 was $6.5 million, $0.8 million and less than $0.1 million.

Other Plans

Direct Stock Purchase Plan

We maintain a Direct Stock Purchase Plan which allows participants to have all or part of their cash dividends paid quarterly in additional shares of our common stock. Through March 2004, participants were permitted to reinvest their cash dividends at a three percent discount from market prices. Effective April 2004, the three percent discount on reinvested dividends was eliminated and the minimum initial investment required to join the plan was increased to $1,250. Direct Stock Purchase Plan participants may purchase additional shares of Atmos common stock as often as weekly with voluntary cash payments of at least $25, up to an annual maximum of $100,000.

Outside Directors Stock-For-Fee Plan

In November 1994, the Board adopted the Outside Directors Stock-for-Fee Plan which was approved by the shareholders of Atmos in February 1995 and was amended and restated in November 1997. The plan permits non-employee directors to receive all or part of their annual retainer and meeting fees in stock rather than in cash.

Equity Incentive and Deferred Compensation Plan for Non-Employee Directors

In November 1998, the Board of Directors adopted the Equity Incentive and Deferred Compensation Plan for Non-Employee Directors which was approved by the shareholders of Atmos in February 1999. This plan amended the Atmos Energy Corporation Deferred Compensation Plan for Outside Directors adopted by the Company in May 1990 and replaced the pension payable under the Company's Retirement Plan for Non-Employee Directors. The plan provides non-employee directors of Atmos with the opportunity to defer receipt, until retirement, of compensation for services rendered to the Company, invest deferred compensation into either a cash account or a stock account and to receive an annual grant of share units for each year of service on the Board.

Other Discretionary Compensation Plans

We created the Variable Pay Plan in fiscal 1999 for our utility segment employees to give each employee an opportunity to share in the success of Atmos based on the achievement of key performance measures

considered critical to achieving business objectives for a given year. These performance measures may include earnings growth objectives, improved cash flow objectives or crucial customer satisfaction and safety results. We monitor progress towards the achievement of the performance measures throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

We implemented the Annual Incentive Plan in October 2001 to give the employees in our nonutility segments an opportunity to share in the success of the nonutility operations. The plan is based upon the net earnings of the nonutility operations and has minimum and maximum thresholds. The plan must meet the minimum threshold in order for the plan to be funded and distributed to employees. We monitor the progress toward the achievement of the thresholds throughout the year and record accruals based upon the expected payout using the best estimates available at the time the accrual is recorded.

9. Retirement and Post-Retirement Employee Benefit Plans

We have both funded and unfunded noncontributory defined benefit plans that together cover substantially all of our employees. We also maintain post-retirement plans that provide health care benefits to retired employees. Finally, we sponsor defined contribution plans which cover substantially all employees. These plans are discussed in further detail below.

Defined Benefit Plans

Employee Pension Plans

As of September 30, 2006, we maintained two defined benefit plans: the Atmos Energy Corporation Pension Account Plan (the Plan) and the Atmos Energy Corporation Retirement Plan for Mississippi Valley Gas Union Employees (the Union Plan) (collectively referred to as the Plans). The Plans are held within the Atmos Energy Corporation Master Retirement Trust (the Master Trust).

The Plan is a cash balance pension plan, that was established effective January 1999 and covers substantially all employees of Atmos. Opening account balances were established for participants as of January 1999 equal to the present value of their respective accrued benefits under the pension plans which were previously in effect as of December 31, 1998. The Plan credits an allocation to each participant's account at the end of each year according to a formula based on the participant's age, service and total pay (excluding incentive pay).

The Plan also provides for an additional annual allocation based upon a participant's age as of January 1, 1999 for those participants who were participants in the prior pension plans. The Plan will credit this additional allocation each year through December 31, 2008. In addition, at the end of each year, a participant's account will be credited with interest on the employee's prior year account balance. A special grandfather benefit also applies through December 31, 2008, for participants who were at least age 50 as of January 1, 1999, and who were participants in one of the prior plans on December 31, 1998. Participants fully vest in their account balances after five years of service and may choose to receive their account balances as a lump sum or an annuity.

The Union Plan is a defined benefit plan that covers substantially all full-time union employees in our Mississippi Division. Under this plan, benefits are based upon years of benefit service and average final earnings. Participants vest in the plan after five years and will receive their benefit in an annuity.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made from time to time as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future.

During fiscal 2006, we voluntarily contributed $2.9 million to the Union Plan. The current year contribution achieved a desired level of funding by satisfying the minimum funding requirements while maximizing the tax deductible contribution for this plan for plan year 2005. During fiscal 2005, we voluntarily contributed $3.0 million to the Master Trust to maintain the level of funding we desire relative to our accumulated benefit obligation. We made the contribution because declining high yield corporate bond yields in the period leading up to our June 30, 2005 measurement date resulted in an increase in the present value of our plan liabilities. We are not required to make a minimum funding contribution during fiscal 2007 nor do we anticipate making any voluntary contributions during fiscal 2007.

We manage the Master Trust's assets with the objective of achieving a rate of return net of inflation of approximately four percent per year. We make investment decisions and evaluate performance on a medium term horizon of at least three to five years. We also consider our current financial status when making recommendations and decisions regarding the Master Trust's assets. Finally, we strive to ensure the Master Trust's assets are appropriately invested to maintain an acceptable level of risk and meet the Master Trust's long term asset allocation policy.

To achieve these objectives, we invest the Master Trust's assets in equity securities, fixed income securities, interests in commingled pension trust funds and cash and cash equivalents. Investments in equity securities are diversified among the market's various subsectors to diversify risk and maximize returns. Fixed income securities are invested in investment grade securities. Cash equivalents are invested in securities that either are short term (less than 180 days) or readily convertible to cash with modest risk.

The following table presents asset allocation information for the Master Trust as of September 30, 2006 and 2005.

Security Class	Targeted Allocation Range	Actual Allocation September 30 2006	2005
Domestic equities	35%-55%	44.3%	45.0%
International equities	10%-20%	15.6%	17.9%
Fixed income	10%-30%	18.8%	18.1%
Company stock	0%-10%	9.2%	9.1%
Other assets	5%-15%	10.7%	9.6%
Cash and equivalents	N/A	1.4%	0.3%

At September 30, 2006 and 2005, the Plan held 1,169,700 shares of Atmos common stock, which represented 9.2 percent and 9.1 percent of total Master Trust assets. These shares generated dividend income for the Plan of approximately $1.5 million during both fiscal 2006 and 2005.

Our employee pension plan expenses and liabilities are determined on an actuarial basis and are affected by numerous assumptions and estimates including the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates and demographic data. We review the estimates and assumptions underlying our employee pension plans annually based upon a June 30 measurement date. The development of our assumptions is fully described in our significant accounting policies in Note 2. The actuarial assumptions used to determine the pension liability for the Plans were determined as of June 30, 2006 and 2005 and the actuarial assumptions used to determine the net periodic pension cost for the Plans were determined as of June 30, 2005, 2004 and 2003. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2006	2005	2006	2005	2004
Discount rate	6.30%	5.00%	5.00%	6.25%	6.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Expected return on plan assets	8.25%	8.50%	8.50%	8.75%	9.00%

The following table presents the Plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2006 and 2005.

	2006	2005
	(In thousands)	
Accumulated benefit obligation	$316,078	$348,383
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$359,924	$312,997
Service cost	13,465	10,401
Interest cost	17,932	19,412
Actuarial loss (gain)	(36,748)	43,313
Benefits paid	(28,109)	(26,199)
Benefit obligation at end of year	326,464	359,924
Change in plan assets:		
Fair value of plan assets at beginning of year	355,939	346,162
Actual return on plan assets	32,005	32,976
Employer contributions	2,879	3,000
Benefits paid	(28,109)	(26,199)
Fair value of plan assets at end of year	362,714	355,939
Reconciliation:		
Funded status	36,250	(3,985)
Unrecognized prior service cost	(4,980)	(5,939)
Unrecognized net loss	65,646	119,270
Net amount recognized	$ 96,916	$109,346

Net periodic pension cost for the Plans for 2006, 2005 and 2004 is recorded as operating expense and included the following components:

	Year Ended September 30		
	2006	2005	2004
		(In thousands)	
Components of net periodic pension cost:			
Service cost	$ 13,465	$ 10,401	$ 7,696
Interest cost	17,932	19,412	19,691
Expected return on assets	(25,598)	(27,541)	(30,097)
Amortization of prior service cost	(959)	(1,028)	(1,028)
Recognized actuarial loss	10,469	6,276	6,555
Net periodic pension cost	$ 15,309	$ 7,520	$ 2,817

Supplemental Executive Benefits Plans

We have a nonqualified Supplemental Executive Benefits Plan which provides additional pension, disability and death benefits to the officers and certain other employees of Atmos. The Supplemental Plan was amended and restated in August 1998. In addition, in August 1998, we adopted the Performance-Based Supplemental Executive Benefits Plan which covers all employees who become officers or division presidents after August 12, 1998 or any other employees selected by our Board of Directors at its discretion.

Similar to our employee pension plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a June 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for the supplemental plans were determined as of June 30, 2006 and 2005 and the actuarial assumptions used to determine the net periodic pension cost for the supplemental plans were determined as of June 30, 2005, 2004 and 2003. These assumptions are presented in the following table:

	Pension Liability		Pension Cost		
	2006	2005	2006	2005	2004
Discount rate	6.30%	5.00%	5.00%	6.25%	6.00%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%

The following table presents the supplemental plans' accumulated benefit obligation, projected benefit obligation and funded status as of September 30, 2006 and 2005.

	2006	2005
	(In thousands)	
Accumulated benefit obligation	$ 79,209	$ 86,661
Change in projected benefit obligation:		
Benefit obligation at beginning of year	$ 97,941	$ 73,998
Service cost	3,001	2,144
Interest cost	4,955	4,658
Actuarial loss (gain)	(14,618)	20,637
Benefits paid	(3,780)	(3,496)
Benefit obligation at end of year	87,499	97,941
Change in plan assets:		
Fair value of plan assets at beginning of year	—	—
Employer contribution	3,780	3,496
Benefits paid	(3,780)	(3,496)
Fair value of plan assets at end of year	—	—
Reconciliation:		
Funded status	(87,499)	(97,941)
Unrecognized prior service cost	1,684	2,706
Unrecognized net loss	22,927	40,334
Accrued pension cost	$(62,888)	$(54,901)

Assets for the supplemental plans are held in separate rabbi trusts and comprise the following:

	Cost	Unrealized Holding Gain	Market Value
		(In thousands)	
As of September 30, 2006:			
Domestic equity mutual funds	$30,562	$1,099	$31,661
Foreign equity mutual funds	5,975	1,542	7,517
	$36,537	$2,641	$39,178
As of September 30, 2005:			
Domestic equity mutual funds	$28,902	$ 897	$29,799
Foreign equity mutual funds	5,133	328	5,461
	$34,035	$1,225	$35,260

At September 30, 2006, we maintained investments in one domestic equity mutual fund and one domestic bond fund that were in unrealized loss positions as of September 30, 2006. Information concerning unrealized losses for our supplemental plan assets follows:

	Less Than 12 Months		12 Months or More	
	Fair Value	Unrealized Loss	Fair Value	Unrealized Loss
	(In thousands)			
Domestic equity mutual funds	$19,963	$773	$—	$—

Because these funds are only used to fund the supplemental plans, we evaluate investment performance over a long-term horizon. Based upon our intent and ability to hold these investments, the short-term nature of the impairment as of September 30, 2006 and our ability to direct the source of the payments in order to maximize the life of the portfolio, the improved investment returns in the last year and the fact that these funds continue to receive good ratings from mutual fund rating companies, we do not consider this impairment to be other-than-temporary.

Net periodic pension cost for the supplemental plans for 2006, 2005 and 2004 is recorded as operating expense and included the following components:

	Year Ended September 30		
	2006	2005	2004
	(In thousands)		
Components of net periodic pension cost:			
Service cost	$ 3,001	$2,144	$2,037
Interest cost	4,955	4,658	4,324
Amortization of transition asset	—	4	96
Amortization of prior service cost	1,022	1,022	1,022
Recognized actuarial loss	2,789	1,290	1,516
Net periodic pension cost	$11,767	$9,118	$8,995

Supplemental Disclosures For Defined Benefit Plans with Accumulated Benefit Obligations in Excess of Plan Assets

The following summarizes key information for our defined benefit plans with accumulated benefit obligations in excess of plan assets. For fiscal 2005 the accumulated benefit obligation for the MVG plan exceeded the fair value of plan assets. For fiscal 2006 and 2005 the accumulated benefit obligation for our supplemental plans exceeded the fair value of plan assets.

	Employee Pension Plans	Supplemental Plans	
	2005	2006	2005
	(In thousands)		
Projected Benefit Obligation	$13,550	$87,499	$97,941
Accumulated Benefit Obligation	10,738	79,209	86,661
Fair Value of Plan Assets	6,465	—	—

Estimated Future Benefit Payments

The following benefit payments for our defined benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following years:

	Pension Plans	Supplemental Plans
	(In thousands)	
2007	$ 32,119	$ 3,729
2008	27,923	4,242
2009	28,588	4,512
2010	29,811	5,262
2011	29,399	5,287
2012-2016	122,553	29,913

Postretirement Benefits

At September 30, 2006, we sponsored the Retiree Medical Plan for Retirees and Disabled Employees of Atmos Energy Corporation (the Atmos Retiree Medical Plan). Effective December 31, 2004, the Atmos Energy Corporation Retiree Welfare Benefits Plan for Certain MVG Non-Union Employees and the Atmos Energy Corporation Retiree Welfare Benefits Plan for MVG Union Employees merged into the Atmos Retiree Medical Plan.

This plan provides medical and prescription drug protection to all qualified participants based on their date of retirement. The Plan provides different levels of benefits depending on the level of coverage chosen by the participants and the terms of predecessor plans; however, we generally pay 80 percent of the projected net claims and administrative costs and participants pay the remaining 20 percent of this cost.

On October 1, 2004, in connection with the acquisition of TXU Gas, we transitioned certain employees from TXU Gas to Atmos Energy Corporation. Although we did not assume the existing employee benefit liabilities or plans of TXU Gas, we received a credit of $18.9 million against the purchase price to permit us to provide partial past service credits for retiree medical benefits under the Atmos Retiree Medical Plan. The $18.9 million credit approximated the actuarially determined present value of the accumulated benefits related to the past service of the transitioned employees on the acquisition date.

Generally, our funding policy is to contribute annually an amount in accordance with the requirements of the Employee Retirement Income Security Act of 1974. However, additional voluntary contributions are made annually as considered necessary. Contributions are intended to provide not only for benefits attributed to service to date but also for those expected to be earned in the future. We expect to contribute $11.4 million to our postretirement benefits plans during fiscal 2007.

We maintain a formal investment policy with respect to the assets in our postretirement benefits plans to ensure the assets funding the postretirement benefit plans are appropriately invested to maintain an acceptable level of risk. We also consider our current financial status when making recommendations and decisions regarding the postretirement benefits plans.

We currently invest the assets funding our postretirement benefit plans in money market funds, equity mutual funds, fixed income funds and a balanced fund. The following table presents asset allocation information for the postretirement benefit plan assets as of September 30, 2006 and 2005.

	Actual Allocation September 30	
Security Class	2006	2005
Diversified investment fund[1]	100%	97.2%
Cash and cash equivalents	—	2.8%

[1] This fund invests in a diversified portfolio of common stocks, preferred stocks and fixed income securities. It may invest up to 75 percent of assets in common stocks and convertible securities.

Similar to our employee pension and supplemental plans, we review the estimates and assumptions underlying our supplemental executive benefit plans annually based upon a June 30 measurement date using the same techniques as our employee pension plans. The actuarial assumptions used to determine the pension liability for our postretirement plan were determined as of June 30, 2006 and 2005 and the actuarial assumptions used to determine the net periodic pension cost for the postretirement plan were determined as of June 30, 2005, 2004 and 2003. The assumptions are presented in the following table:

	Postretirement Liability		Postretirement Cost		
	2006	2005	2006	2005	2004
Discount rate	6.30%	5.00%	5.00%	6.25%	6.19%
Expected return on plan assets	5.20%	5.30%	5.30%	5.30%	5.30%
Initial trend rate	8.00%	9.00%	9.00%	10.00%	9.00%
Ultimate trend rate	5.00%	5.00%	5.00%	5.00%	5.00%
Ultimate trend reached in	2010	2010	2010	2010	2008

The following table presents the postretirement plan's benefit obligation and funded status as of September 30, 2006 and 2005.

	2006	2005
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 170,930	$ 125,189
Service cost	13,083	9,968
Interest cost	8,840	9,369
Plan participants' contributions	1,340	2,131
Actuarial loss (gain)	(22,657)	16,449
Acquisition	—	18,878
Benefits paid	(10,695)	(11,054)
Subsidy payments	60	—
Benefit obligation at end of year	160,901	170,930
Change in plan assets:		
Fair value of plan assets at beginning of year	39,843	36,408
Actual return on plan assets	3,703	2,365
Employer contributions	10,609	9,993
Plan participants' contributions	1,340	2,131
Benefits paid	(10,695)	(11,054)
Fair value of plan assets at end of year	44,800	39,843
Reconciliation:		
Funded status	(116,101)	(131,087)
Unrecognized transition obligation	11,154	12,665
Unrecognized prior service cost	33	394
Unrecognized net loss	3,060	28,513
Accrued postretirement cost	$(101,854)	$ (89,515)

Net periodic postretirement cost for 2006, 2005 and 2004 is recorded as operating expense and included the components presented below. The 2006, 2005 and 2004 amounts reflect the impact of adopting the provisions of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) beginning in the second quarter of fiscal 2004 as the plan is considered "actuarially equivalent" to Medicare Part D.

	Year Ended September 30		
	2006	2005	2004
	(In thousands)		
Components of net periodic postretirement cost:			
Service cost	$13,083	$ 9,968	$ 5,941
Interest cost	8,840	9,369	7,355
Expected return on assets	(2,187)	(2,070)	(1,523)
Amortization of transition obligation	1,511	1,511	1,511
Amortization of prior service cost	361	386	386
Recognized actuarial loss	1,280	622	635
Net periodic postretirement cost	$22,888	$19,786	$14,305

Assumed health care cost trend rates have a significant effect on the amounts reported for the plan. A one-percentage point change in assumed health care cost trend rates would have the following effects on the latest actuarial calculations:

	1-Percentage Point Increase	1-Percentage Point Decrease
	(In thousands)	
Effect on total service and interest cost components	$ 3,782	$ (3,064)
Effect on postretirement benefit obligation	$17,678	$(14,974)

We are currently recovering other postretirement benefits costs through our regulated rates under SFAS 106 accrual accounting in substantially all of our service areas. Other postretirement benefits costs have been specifically addressed in rate orders in each jurisdiction served by our Mid-States Division and our Mississippi Division or have been included in a rate case and not disallowed. Management believes that accrual accounting in accordance with SFAS 106 is appropriate and will continue to seek rate recovery of accrual-based expenses in its ratemaking jurisdictions that have not yet approved the recovery of these expenses.

Estimated Future Benefit Payments

The following benefit payments paid by us, retirees and prescription drug subsidy payments for our postretirement benefit plans, which reflect expected future service, as appropriate, are expected to be paid in the following years:

	Company Payments	Retiree Payments	Subsidy Payments	Total Postretirement Benefits
		(In thousands)		
2007	$11,408	$ 2,249	$127	$ 13,784
2008	10,180	2,574	32	12,786
2009	11,404	2,743	—	14,147
2010	12,520	3,015	—	15,535
2011	13,621	3,278	—	16,899
2012-2016	86,065	20,698	—	106,763

Defined Contribution Plans

As of September 30, 2006, we maintained two defined contribution benefit plans: the Atmos Energy Corporation Retirement Savings Plan and Trust (the Retirement Savings Plan) and the Atmos Energy Corporation Savings Plan for MVG Union Employees (the Union 401K Plan).

The Retirement Savings Plan covers substantially all employees and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Participants may elect a salary reduction ranging from a minimum of one percent up to a maximum of 65 percent of eligible compensation, as defined by the Plan, not to exceed the maximum allowed by the Internal Revenue Service. We match 100 percent of a participant's contributions, limited to four percent of the participant's salary, in Atmos common stock. However, participants have the option to immediately transfer this matching contribution into other funds held within the plan. Participants are eligible to receive matching contributions after completing one year of service. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

The Union 401K Plan covers substantially all Mississippi Division employees who are members of the International Chemical Workers Union Council, United Food and Commercial Workers Union International (the Union) and is subject to the provisions of Section 401(k) of the Internal Revenue Code. Employees of the Union automatically become participants of the Union 401K plan on the date of union employment. We match 50 percent of a participant's contribution, limited to six percent of the participant's eligible contribution. Participants are also permitted to take out loans against their accounts subject to certain restrictions.

Matching contributions to our defined contribution plans are expensed as incurred and amounted to $7.0 million, $5.7 million, and $4.6 million for 2006, 2005 and 2004. The Board of Directors may also approve discretionary contributions, subject to the provisions of the Internal Revenue Code of 1986 and applicable regulations of the Internal Revenue Service. No discretionary contributions were made for 2006, 2005 or 2004. At September 30, 2006 and 2005, the Retirement Savings Plan held 3.2 percent and 3.1 percent of our outstanding common stock.

10. Details of Selected Consolidated Balance Sheet Captions

The following tables provide additional information regarding the composition of certain of our balance sheet captions.

Accounts receivable

Accounts receivable was comprised of the following at September 30, 2006 and 2005:

	September 30	
	2006	2005
	(In thousands)	
Billed accounts receivable	$321,279	$381,469
Unbilled revenue	44,607	62,337
Other accounts receivable	22,429	26,120
Total accounts receivable	388,315	469,926
Less: allowance for doubtful accounts	(13,686)	(15,613)
Net accounts receivable	$374,629	$454,313

Other current assets

Other current assets as of September 30, 2006 and 2005 were comprised of the following accounts.

	September 30	
	2006	2005
	(In thousands)	
Assets from risk management activities	$ 12,553	$107,913
Deferred gas cost	44,992	38,173
Taxes receivable	56,034	—
Current deferred tax asset	18,943	67,365
Prepaid expenses	16,379	13,334
Current portion of leased assets receivable	2,973	2,973
Materials and supplies	6,088	7,502
Other	11,990	978
Total	$169,952	$238,238

Property, plant and equipment

Property, plant and equipment was comprised of the following as of September 30, 2006 and 2005:

	September 30	
	2006	2005
	(In thousands)	
Production plant	$ 12,563	$ 19,401
Storage plant	118,902	116,708
Transmission plant	863,882	753,499
Distribution plant	3,404,220	3,164,316
General plant	541,852	502,189
Intangible plant	85,059	75,571
	5,026,478	4,631,684
Construction in progress	74,830	133,926
	5,101,308	4,765,610
Less: accumulated depreciation and amortization	(1,472,152)	(1,391,243)
Net property, plant and equipment	$ 3,629,156	$ 3,374,367

Deferred charges and other assets

Deferred charges and other assets as of September 30, 2006 and 2005 were comprised of the following accounts.

	September 30	
	2006	2005
	(In thousands)	
Pension plan assets in excess of plan obligations	$ 96,916	$109,346
Marketable securities	39,178	35,260
Long-term receivable on leased assets	16,440	19,413
Regulatory assets	30,823	37,844
Deferred financing costs	42,673	47,792
Assets from risk management activities	6,186	735
Other	2,109	26,553
Total	$234,325	$276,943

Other current liabilities

Other current liabilities as of September 30, 2006 and 2005 were comprised of the following accounts.

	September 30	
	2006	2005
	(In thousands)	
Customer deposits	$102,555	$ 89,918
Accrued employee costs	27,276	26,409
Deferred gas costs	68,959	134,048
Accrued interest	54,892	53,675
Liabilities from risk management activities	30,669	61,920
Taxes payable	50,673	66,083
Post-retirement obligations	8,850	5,300
Regulatory cost of removal accrual	15,114	11,565
Other	29,463	54,450
Total	$388,451	$503,368

Deferred credits and other liabilities

Deferred credits and other liabilities as of September 30, 2006 and 2005 were comprised of the following accounts.

	September 30	
	2006	2005
	(In thousands)	
Post-retirement obligations	$ 93,004	$ 84,215
Nonqualified retirement plan obligation	62,888	54,901
Customer advances for construction	17,481	18,872
Liabilities from risk management activities	276	15,316
Deferred revenue	4,049	5,488
Regulatory liabilities	10,825	8,084
Asset retirement obligation	15,070	—
Other	785	12,739
Total	$204,378	$199,615

11. Earnings Per Share

Basic and diluted earnings per share for the years ended September 30 are calculated as follows:

	2006	2005	2004
	(In thousands, except per share data)		
Net income	$147,737	$135,785	$86,227
Denominator for basic income per share — weighted average common shares	80,731	78,508	54,021
Effect of dilutive securities:			
Restricted and other shares	551	360	281
Stock options	108	144	114
Denominator for diluted income per share — weighted average common shares	81,390	79,012	54,416
Net income per share — basic	$ 1.83	$ 1.73	$ 1.60
Net income per share — diluted	$ 1.82	$ 1.72	$ 1.58

There were no out-of-the-money options excluded from the computation of diluted earnings per share for the year ended September 30, 2006 and 2005. There were approximately 3,000 out-of-the-money options excluded from the computation of diluted earnings per share for the year ended September 30, 2004 as their exercise price was greater than the average market price of the common stock during that period.

12. Income Taxes

The components of income tax expense from continuing operations for 2006, 2005 and 2004 were as follows:

	2006	2005	2004
		(In thousands)	
Current			
Federal	$ 838	$61,508	$ 9,003
State	2,623	8,569	2,021
Deferred			
Federal	77,154	11,453	35,970
State	9,024	1,217	5,079
Investment tax credits	(486)	(514)	(535)
	$89,153	$82,233	$51,538

Reconciliations of the provision for income taxes computed at the statutory rate to the reported provisions for income taxes from continuing operations for 2006, 2005 and 2004 are set forth below:

	2006	2005	2004
		(In thousands)	
Tax at statutory rate of 35%	$82,912	$76,306	$48,218
Common stock dividends deductible for tax reporting	(1,180)	(1,088)	(985)
State taxes (net of federal benefit)	7,570	6,361	4,615
Other, net	(149)	654	(310)
Income tax expense	$89,153	$82,233	$51,538

Deferred income taxes reflect the tax effect of differences between the basis of assets and liabilities for book and tax purposes. The tax effect of temporary differences that give rise to significant components of the deferred tax liabilities and deferred tax assets at September 30, 2006 and 2005 are presented below:

	2006	2005
	(In thousands)	
Deferred tax assets:		
Costs expensed for book purposes and capitalized for tax purposes	$ 6,469	$ 1,299
Accruals not currently deductible for tax purposes	7,709	13,319
Customer advances	6,643	8,455
Nonqualified benefit plans	26,337	24,869
Postretirement benefits	37,558	33,176
Treasury lock agreement	12,589	14,698
Unamortized investment tax credit	680	864
Regulatory liabilities	1,460	9,836
Tax net operating loss and credit carryforwards	5,623	855
Gas cost adjustments	19,434	36,432
Other, net	4,525	9,781
Total deferred tax assets	129,027	153,584
Deferred tax liabilities:		
Difference in net book value and net tax value of assets	(364,438)	(317,834)
Pension funding	(37,188)	(42,597)
Regulatory assets	(1,695)	(13,021)
Cost capitalized for book purposes and expensed for tax purposes	(1,618)	(2,739)
Difference between book and tax on mark to market accounting	(9,536)	(82)
Other, net	(1,781)	(2,153)
Total deferred tax liabilities	(416,256)	(378,426)
Net deferred tax liabilities	$(287,229)	$(224,842)
SFAS No. 109 deferred credits for rate regulated entities	$ 2,687	$ 2,833

We have tax carryforwards amounting to $5.6 million. The tax carryforwards include net operating losses for federal purposes amounting to $4.3 million and state net operating losses amounting to $1.3 million. The federal net operating loss carryforwards will expire in 2026. Depending on the jurisdiction in which the net operating loss was generated, the state net operating losses will begin to expire between 2011 and 2026.

The Internal Revenue Service is currently conducting a routine examination of our fiscal 2002, 2003 and 2004 tax returns. We believe all material tax items which relate to the years under audit have been properly accrued.

13. Commitments and Contingencies

Litigation

Colorado-Kansas Division

We are a defendant in a lawsuit originally filed by Quinque Operating Company, Tom Boles and Robert Ditto in September 1999 in the District Court of Stevens County, Kansas against more than 200 companies in the natural gas industry. The plaintiffs, who purport to represent a class of royalty owners, allege that the defendants have underpaid royalties on gas taken from wells situated on non-federal and non-Indian lands in Kansas, predicated upon allegations that the defendants' gas measurements were inaccurate. The plaintiffs have not specifically alleged an amount of damages. We are also a defendant, along with over 50 other companies in the natural gas industry, in another proposed class action lawsuit filed in the same court by Will Price, Tom Boles and The Cooper Clarke Foundation in May 2003 involving similar allegations. We believe that the plaintiffs' claims are lacking in merit and we intend to vigorously defend these actions. While the results cannot be predicted with certainty, we believe the final outcome of such litigation will not have a material adverse effect on our financial conditions, results of operations or net cash flows. We were also a defendant in another lawsuit entitled *In Re Natural Gas Royalties Qui Tam Litigation*, involving similar allegations filed in June 1997 in the United States District Court for the District of Colorado, which was later transferred to the United States District Court for the District of Wyoming, where it was consolidated with approximately 50 additional lawsuits in October 1999. On October 20, 2006, the District Court granted the defendants' motion to dismiss this lawsuit for lack of subject matter jurisdiction.

United Cities Propane Gas, Inc.

United Cities Propane Gas, Inc., one of our wholly-owned subsidiaries, was a party to an action filed in June 2000 that was pending in the Circuit Court of Sevier County, Tennessee. The plaintiffs' claims arose out of injuries alleged to have been caused by a low-level propane explosion. The plaintiffs were seeking to recover damages of $13.0 million. The case was settled on November 14, 2006. As the settlement amount was fully covered by insurance, the settlement did not have a material adverse effect on our financial condition, results of operations or net cash flows.

We are a party to other litigation and claims that arose in the ordinary course of our business, including certain litigation and claims that arose in the ordinary course of the business of TXU Gas Company, the natural gas distribution and pipeline operations we acquired on October 1, 2004. While the results of such litigation and claims cannot be predicted with certainty, we believe the final outcome of such litigation and claims will not have a material adverse effect on our financial condition, results of operations or net cash flows.

Environmental Matters

Former Manufactured Gas Plant Sites

We are the owner or previous owner of former manufactured gas plant sites in Johnson City and Bristol, Tennessee, Keokuk, Iowa, and Hannibal, Missouri, which were used to supply gas prior to the availability of natural gas. The gas manufacturing process resulted in certain byproducts and residual materials, including coal tar. The manufacturing process used by our predecessors was an acceptable and satisfactory process at the time such operations were being conducted. Under current environmental protection laws and regulations, we may be responsible for response actions with respect to such materials if response actions are necessary.

United Cities Gas Company and the Tennessee Department of Environment and Conservation (TDEC) entered into a consent order effective in January 1997, to facilitate the investigation, removal and remediation of the Johnson City site. Prior to our merger with United Cities Gas Company in July 1997, United Cities Gas

Company began the implementation of the consent order in the first quarter of fiscal 1997, which will continue for the foreseeable future. The investigative phase of the work at the site has been completed, and an interim removal action was completed in June 2001. We installed four groundwater monitoring wells at the site in 2002 and have submitted the analytical results to the TDEC. We completed a risk assessment report that has been approved by the TDEC as well as a feasibility study for this site, which was submitted to the TDEC in October 2003. The feasibility study recommends a remedial action that will limit the use of and access to the impacted soil, cap the site with the addition of a clay fill and geosynthetic liner and groundwater monitoring for a period of up to 30 years. The feasibility study was approved by the TDEC in February 2005. The estimated cost of the remedial action is $1.5 million, which is comprised primarily of operating and maintenance costs that would be associated with a groundwater monitoring project. In January 2006, the TDEC issued a Record of Decision approving the remedial action recommended in the feasibility study. The Tennessee Regulatory Authority granted us permission to defer, until our next rate case in Tennessee, all costs incurred in Tennessee in connection with state and federally mandated environmental control requirements.

In March 2002, the TDEC contacted us about conducting an investigation at a former manufactured gas plant located in Bristol, Tennessee. We agreed to perform a preliminary investigation at the site, which we completed in June 2002. The investigation identified manufactured gas plant residual materials in the soil beneath the site, and we have proposed performing a focused removal action to remove any such residuals. The TDEC requested that the focused removal action be conducted pursuant to a voluntary agreement. In April 2004, we entered into a voluntary consent agreement with the TDEC for the performance of the removal action and the removal action was completed in November 2004. In September 2005, we filed site use limitations on the property in the local property records, including restrictions on the use of the site to commercial and industrial purposes and a prohibition of the use of groundwater for use as drinking water were filed. In February 2006, we received a Completion Letter from the TDEC informing us that no further action is required at this site pursuant to the voluntary consent agreement with the TDEC.

In July 1998, we entered into an Abatement Order on Consent with the Missouri Department of Natural Resources to address the former manufactured gas plant located in Hannibal, Missouri. We agreed to perform a removal action and a subsequent site evaluation and to reimburse the response costs incurred by the state of Missouri in connection with the property. The removal action was conducted and completed in August 1998, and the site-evaluation field work was conducted in August 1999. A risk assessment for the site has been approved by the Missouri Department of Natural Resources. In preparation for the risk assessment, we executed and recorded certain site-use limitations, including restricting use of the site to commercial and industrial purposes and prohibiting the withdrawal of groundwater for use as drinking water. In addition, we have installed a geosynthetic liner over the surface of the site.

In 1995, United Cities Gas Company entered into an agreement with a third party to resolve its share of the costs of additional investigations and environmental-response actions for soil contamination at a former manufactured gas plant in Keokuk, Iowa. However, the extent of groundwater contamination at the site, if any, which is not covered by the agreement, has yet to be determined.

As of September 30, 2006, we had incurred costs of approximately $2.3 million for the investigations of the Johnson City and Bristol, Tennessee, and Hannibal, Missouri sites.

We are a party to other environmental matters and claims that have arisen in the ordinary course of our business. While the ultimate results of response actions to these environmental matters and claims cannot be predicted with certainty, we believe the final outcome of such response actions will not have a material adverse effect on our financial condition, results of operations or net cash flows because we believe that the expenditures related to such response actions will either be recovered through rates, shared with other parties or are adequately covered by insurance.

Purchase Commitments

AEM has commitments to purchase physical quantities of natural gas under contracts indexed to the forward NYMEX strip or fixed price contracts. At September 30, 2006, AEM was committed to purchase 61.7 Bcf within one year, 51.2 Bcf within one to three years and 0.8 Bcf after three years under indexed contracts. AEM is committed to purchase 2.4 Bcf within one year and 0.1 Bcf within one to three years under fixed price contracts with prices ranging from $3.40 to $12.00. Purchases under these contracts totaled $2,124.3 million, $1,421.2 million and $1,252.2 million for 2006, 2005 and 2004.

Our utility divisions, except for our Mid-Tex Division, maintain supply contracts with several vendors that generally cover a period of up to one year. Commitments for estimated base gas volumes are established under these contracts on a monthly basis at contractually negotiated prices. Commitments for incremental daily purchases are made as necessary during the month in accordance with the terms of the individual contract.

Our Mid-Tex Division maintains long-term supply contracts to ensure a reliable source of gas for our customers in its service area which obligate it to purchase specified volumes at market prices. The estimated commitments under these contracts as of September 30, 2006 are as follows (in thousands):

2007	$560,461
2008	101,702
2009	9,091
2010	8,518
2011	8,517
Thereafter	19,928
	$708,217

14. Leases

Leasing Operations

Atmos Power Systems, Inc. constructs electric peaking power-generating plants and associated facilities and enters into agreements to either lease or sell these plants. We completed a sales-type lease transaction for one distributed electric generation plant in 2001 and a second sales-type lease transaction in 2003. In connection with these lease transactions, as of September 30, 2006 and 2005, we had receivables of $19.4 million and $22.4 million and recognized income of $1.7 million, $1.6 million and $1.9 million for fiscal years 2006, 2005 and 2004. The future minimum lease payments to be received for each of the five succeeding years are as follows:

	Minimum Lease Receipts
	(In thousands)
2007	$ 2,973
2008	2,973
2009	2,973
2010	2,973
2011	2,973
Thereafter	4,548
Total minimum lease receipts	$19,413

Capital and Operating Leases

We have entered into non-cancelable operating leases for office and warehouse space used in our operations. The remaining lease terms range from one to 20 years and generally provide for the payment of taxes, insurance and maintenance by the lessee. Renewal options exist for certain of these leases. We have also entered into capital leases for division offices and operating facilities. Property, plant and equipment included amounts for capital leases of $5.8 million at September 30, 2006 and 2005. Accumulated depreciation for these capital leases totaled $4.2 million and $3.8 million at September 30, 2006 and 2005. Depreciation expense for these assets is included in consolidated depreciation expense on the consolidated statement of income.

The related future minimum lease payments at September 30, 2006 were as follows:

	Capital Leases	Operating Leases
	(In thousands)	
2007	$ 433	$ 15,959
2008	362	15,463
2009	311	14,694
2010	291	13,502
2011	186	13,410
Thereafter	1,194	103,778
Total minimum lease payments	2,777	$176,806
Less amount representing interest	1,205	
Present value of net minimum lease payments	$1,572	

Consolidated lease and rental expense amounted to $11.4 million, $9.5 million and $8.1 million for fiscal 2006, 2005 and 2004.

15. Concentration of Credit Risk

Credit risk is the risk of financial loss to us if a customer fails to perform its contractual obligations. We engage in transactions for the purchase and sale of products and services with major companies in the energy industry and with industrial, commercial, residential and municipal energy consumers. These transactions principally occur in the southern and midwestern regions of the United States. We believe that this geographic concentration does not contribute significantly to our overall exposure to credit risk. Credit risk associated with trade accounts receivable for the utility segment is mitigated by the large number of individual customers and diversity in our customer base. Due to minimal receivables, the credit risk for our other nonutility segment is not significant.

Customer diversification also helps mitigate AEM's exposure to credit risk. AEM maintains credit policies with respect to its counterparties that it believes minimizes overall credit risk. Where appropriate, such policies include the evaluation of a prospective counterparty's financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. AEM also monitors the financial condition of existing counterparties on an ongoing basis. Customers not meeting minimum standards are required to provide adequate assurance of financial performance.

AEM maintains a provision for credit losses based upon factors surrounding the credit risk of customers, historical trends and other information. We believe, based on our credit policies and our provisions for credit

losses, that our financial position, results of operations and cash flows will not be materially affected as a result of nonperformance by any single counterparty.

AEM's estimated credit exposure is monitored in terms of the percentage of its customers that are rated as investment grade versus non-investment grade. Credit exposure is defined as the total of (1) accounts receivable, (2) delivered, but unbilled physical sales and (3) mark-to-market exposure for sales and purchases. Investment grade determinations are set internally by AEM's credit department, but are primarily based on external ratings provided by Moody's Investors Service Inc. (Moody's) and/or Standard & Poor's Corporation (S&P). For non-rated entities, the default rating for municipalities is investment grade, while the default rating for non-guaranteed industrials and commercials is non-investment grade. The following table shows the percentages related to the investment ratings as of September 30, 2006 and 2005.

	September 30, 2006	September 30, 2005
Investment grade	40%	49%
Non-investment grade	60%	51%
Total	100%	100%

The following table presents our derivative counterparty credit exposure by operating segment based upon the unrealized fair value of our derivative contracts that represent assets as of September 30, 2006. Investment grade counterparties have minimum credit ratings of BBB-, assigned by Standard & Poor's Rating Group; or Baa3, assigned by Moody's Investor Service. Non-investment grade counterparties are composed of counterparties that are below investment grade or that have not been assigned an internal investment grade rating due to the short-term nature of the contracts associated with that counterparty. This category is composed of numerous smaller counterparties, none of which is individually significant.

	Utility Segment[1]	Natural Gas Marketing Segment	Consolidated
		(In thousands)	
Investment grade counterparties	$—	$16,001	$16,001
Non-investment grade counterparties	—	2,738	2,738
	$—	$18,739	$18,739

[1] Counterparty risk for our utility segment is minimized because hedging gains and losses are passed through to our customers.

16. Supplemental Cash Flow Disclosures

Supplemental disclosures of cash flow information for 2006, 2005 and 2004 are presented below.

	2006	2005	2004
		(In thousands)	
Cash paid for interest	$149,031	$103,418	$65,700
Cash paid for income taxes	$ 77,265	$ 51,490	$ 1,677

There were no significant noncash investing and financing transactions during fiscal 2006, 2005 and 2004. All cash flows and non cash activities related to our commodity derivatives are considered as operating activities.

17. Segment Information

Atmos Energy Corporation and its subsidiaries are engaged primarily in the natural gas utility business as well as certain nonutility businesses. We distribute natural gas through sales and transportation arrangements to approximately 3.2 million residential, commercial, public-authority and industrial customers throughout our seven regulated utility divisions, which cover service areas located in 12 states. In addition, we transport natural gas for others through our distribution system.

Through our nonutility businesses, we provide natural gas management and marketing services to industrial customers, municipalities and other local distribution companies located in 22 states. Additionally, we provide natural gas transportation and storage services to certain of our utility operations and to third parties.

Our operations are divided into four segments:

- The utility segment, which includes our regulated natural gas distribution and related sales operations,
- The natural gas marketing segment, which includes a variety of nonregulated natural gas management services,
- The pipeline and storage segment, which includes our regulated and nonregulated natural gas transmission and storage services and
- The other nonutility segment, which includes all of our other nonregulated nonutility operations.

Our determination of reportable segments considers the strategic operating units under which we manage sales of various products and services to customers in differing regulatory environments. Although our utility segment operations are geographically dispersed, they are reported as a single segment as each utility division has similar economic characteristics. The accounting policies of the segments are the same as those described in the summary of significant accounting policies. We evaluate performance based on net income or loss of the respective operating units. Interest expense is allocated pro rata to each segment based upon our net investment in each segment. Income taxes are allocated to each segment as if each segment's taxes were calculated on a separate return basis.

Summarized income statements and capital expenditures by segment are shown in the following tables.

	Year Ended September 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$3,649,851	$2,418,856	$ 81,857	$1,799	$ —	$6,152,363
Intersegment revenues	740	737,668	78,710	4,099	(821,217)	—
	3,650,591	3,156,524	160,567	5,898	(821,217)	6,152,363
Purchased gas cost	2,725,534	3,025,897	838	—	(816,476)	4,935,793
Gross profit	925,057	130,627	159,729	5,898	(4,741)	1,216,570
Operating expenses						
Operation and maintenance	357,519	22,223	53,641	5,013	(4,978)	433,418
Depreciation and amortization	164,493	1,834	19,166	103	—	185,596
Taxes, other than income	178,204	4,335	9,064	390	—	191,993
Impairment of long-lived assets	22,947	—	—	—	—	22,947
Total operating expenses	723,163	28,392	81,871	5,506	(4,978)	833,954
Operating income	201,894	102,235	77,858	392	237	382,616
Miscellaneous income	9,506	2,598	2,554	4,151	(17,928)	881
Interest charges	126,489	8,510	25,331	3,968	(17,691)	146,607
Income before income taxes	84,911	96,323	55,081	575	—	236,890
Income tax expense	31,909	37,757	19,457	30	—	89,153
Net income	$ 53,002	$ 58,566	$ 35,624	$ 545	$ —	$ 147,737
Capital expenditures	$ 307,742	$ 909	$116,673	$ —	$ —	$ 425,324

	Year Ended September 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$3,102,041	$1,783,926	$ 73,880	$2,026	$ —	$4,961,873
Intersegment revenues	1,099	322,352	79,409	3,276	(406,136)	—
	3,103,140	2,106,278	153,289	5,302	(406,136)	4,961,873
Purchased gas cost	2,195,774	2,044,305	6,811	—	(402,654)	3,844,236
Gross profit	907,366	61,973	146,478	5,302	(3,482)	1,117,637
Operating expenses						
Operation and maintenance	346,594	18,444	50,773	4,153	(3,683)	416,281
Depreciation and amortization	159,497	1,896	16,504	108	—	178,005
Taxes, other than income	164,910	648	8,915	223	—	174,696
Total operating expenses	671,001	20,988	76,192	4,484	(3,683)	768,982
Operating income	236,365	40,985	70,286	818	201	348,655
Miscellaneous income	6,776	771	2,030	2,575	(10,131)	2,021
Interest charges	112,382	3,405	24,579	2,222	(9,930)	132,658
Income before income taxes	130,759	38,351	47,737	1,171	—	218,018
Income tax expense	49,642	14,947	17,138	506	—	82,233
Net income	$ 81,117	$ 23,404	$ 30,599	$ 665	$ —	$ 135,785
Capital expenditures	$ 300,574	$ 649	$ 31,960	$ —	$ —	$ 333,183

	Year Ended September 30, 2004					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
Operating revenues from external parties	$1,636,636	$1,279,424	$ 1,617	$2,360	$ —	$2,920,037
Intersegment revenues	1,092	339,178	18,141	1,033	(359,444)	—
	1,637,728	1,618,602	19,758	3,393	(359,444)	2,920,037
Purchased gas cost	1,134,594	1,571,971	9,383	—	(358,102)	2,357,846
Gross profit	503,134	46,631	10,375	3,393	(1,342)	562,191
Operating expenses						
Operation and maintenance	195,471	15,692	2,533	2,150	(1,376)	214,470
Depreciation and amortization	92,954	2,089	1,488	116	—	96,647
Taxes, other than income	54,819	1,124	1,061	375	—	57,379
Total operating expenses	343,244	18,905	5,082	2,641	(1,376)	368,496
Operating income	159,890	27,726	5,293	752	34	193,695
Miscellaneous income	5,847	843	289	8,290	(5,762)	9,507
Interest charges	65,399	2,711	1,053	2,002	(5,728)	65,437
Income before income taxes	100,338	25,858	4,529	7,040	—	137,765
Income tax expense	37,242	9,225	1,762	3,309	—	51,538
Net income	$ 63,096	$ 16,633	$ 2,767	$3,731	$ —	$ 86,227
Capital expenditures	$ 189,291	$ 520	$ 474	$ —	$ —	$ 190,285

The following table summarizes our revenues by products and services for the year ended September 30.

	2006	2005	2004
		(In thousands)	
Utility revenues:			
Gas sales revenues:			
Residential	$2,068,736	$1,791,172	$ 923,773
Commercial	1,061,783	869,722	400,704
Industrial	276,186	229,649	155,336
Agricultural	40,664	27,889	31,851
Public authority and other	103,936	86,853	77,178
Total gas sales revenues	3,551,305	3,005,285	1,588,842
Transportation revenues	61,475	58,897	30,622
Other gas revenues	37,071	37,859	17,172
Total utility revenues	3,649,851	3,102,041	1,636,636
Natural gas marketing revenues	2,418,856	1,783,926	1,279,424
Pipeline and storage revenues	81,857	73,880	1,617
Other nonutility revenues	1,799	2,026	2,360
Total operating revenues	$6,152,363	$4,961,873	$2,920,037

Balance sheet information at September 30, 2006 and 2005 by segment is presented in the following tables:

	September 30, 2006					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
	(In thousands)					
ASSETS						
Property, plant and equipment, net	$3,083,301	$ 7,531	$537,028	$ 1,296	$ —	$3,629,156
Investment in subsidiaries	281,143	(2,155)	—	—	(278,988)	—
Current assets						
Cash and cash equivalents	8,738	45,481	—	21,596	—	75,815
Cash held on deposit in margin account	—	35,647	—	—	—	35,647
Assets from risk management activities	—	13,164	19,040	—	(19,651)	12,553
Other current assets	714,472	261,435	26,325	8,119	(16,821)	993,530
Intercompany receivables	602,809	—	—	—	(602,809)	—
Total current assets	1,326,019	355,727	45,365	29,715	(639,281)	1,117,545
Intangible assets	—	3,152	—	—	—	3,152
Goodwill	567,221	24,282	143,866	—	—	735,369
Noncurrent assets from risk management activities	—	6,190	5	—	(9)	6,186
Deferred charges and other assets	204,617	1,315	5,301	16,906	—	228,139
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,648,098	$139,863	$107,640	$33,640	$(281,143)	$1,648,098
Long-term debt	2,176,473	—	—	3,889	—	2,180,362
Total capitalization	3,824,571	139,863	107,640	37,529	(281,143)	3,828,460
Current liabilities						
Current maturities of long-term debt	1,250	—	—	1,936	—	3,186
Short-term debt	382,416	—	—	—	—	382,416
Liabilities from risk management activities	27,209	22,500	531	—	(19,571)	30,669
Other current liabilities	473,101	183,077	61,458	—	(14,746)	702,890
Intercompany payables	—	75,665	525,895	1,249	(602,809)	—
Total current liabilities	883,976	281,242	587,884	3,185	(637,126)	1,119,161
Deferred income taxes	297,821	(25,777)	31,927	2,201	—	306,172
Noncurrent liabilities from risk management activities	—	280	5	—	(9)	276
Regulatory cost of removal obligation	261,376	—	—	—	—	261,376
Deferred credits and other liabilities	194,557	434	4,109	5,002	—	204,102
	$5,462,301	$396,042	$731,565	$47,917	$(918,278)	$5,719,547

	September 30, 2005					
	Utility	Natural Gas Marketing	Pipeline and Storage	Other Nonutility	Eliminations	Consolidated
			(In thousands)			
ASSETS						
Property, plant and equipment, net	$2,926,096	$ 7,278	$439,574	$ 1,419	$ —	$3,374,367
Investment in subsidiaries	231,342	(1,896)	—	—	(229,446)	—
Current assets						
Cash and cash equivalents	10,663	28,949	—	504	—	40,116
Cash held on deposit in margin account	4,170	76,786	—	—	—	80,956
Assets from risk management activities	93,310	39,528	1,739	—	(26,664)	107,913
Other current assets	666,081	421,777	36,208	63,820	(152,441)	1,035,445
Intercompany receivables	505,728	—	—	20,133	(525,861)	—
Total current assets	1,279,952	567,040	37,947	84,457	(704,966)	1,264,430
Intangible assets	—	3,507	—	—	—	3,507
Goodwill	566,800	24,282	143,198	—	—	734,280
Noncurrent assets from risk management activities	—	2,073	1,338	—	(2,676)	735
Deferred charges and other assets	249,179	1,461	5,737	19,831	—	276,208
	$5,253,369	$603,745	$627,794	$105,707	$(937,088)	$5,653,527
CAPITALIZATION AND LIABILITIES						
Shareholders' equity	$1,602,422	$144,827	$ 53,426	$ 33,089	$(231,342)	$1,602,422
Long-term debt	2,177,279	—	—	5,825	—	2,183,104
Total capitalization	3,779,701	144,827	53,426	38,914	(231,342)	3,785,526
Current liabilities						
Current maturities of long-term debt	1,250	—	—	2,014	—	3,264
Short-term debt	144,809	60,000	—	51,320	(111,320)	144,809
Liabilities from risk management activities	—	63,936	25,038	—	(27,054)	61,920
Other current liabilities	623,300	217,777	95,557	4,963	(38,835)	902,762
Intercompany payables	—	87,968	437,893	—	(525,861)	—
Total current liabilities	769,359	429,681	558,488	58,297	(703,070)	1,112,755
Deferred income taxes	268,108	12,369	9,563	2,167	—	292,207
Noncurrent liabilities from risk management activities	—	16,654	1,338	—	(2,676)	15,316
Regulatory cost of removal obligation	263,424	—	—	—	—	263,424
Deferred credits and other liabilities	172,777	214	4,979	6,329	—	184,299
	$5,253,369	$603,745	$627,794	$105,707	$(937,088)	$5,653,527

18. Related Party Transactions

AEM provides a variety of natural gas management services to our Kentucky, Louisiana and Mid-States divisions including furnishing natural gas supplies at fixed and market-based prices and the management of certain of our underground storage facilities. Additionally, at times, AEM places financial instruments for our various divisions to partially insulate us and our customers from gas price volatility.

Atmos Pipeline and Storage, L.L.C. provides asset management services for certain of our utility storage fields in exchange for a contractually negotiated demand charge. The Atmos Pipeline — Texas Division, a division of Atmos, provides natural gas transportation services to our Atmos Energy Mid-Tex Division.

Atmos Energy Services, L.L.C., provides natural gas management services for our own utility operations, other than the Mid-Tex Division. Prior to the second quarter of fiscal 2004, this entity conducted limited operations. However, beginning in April 2004, AES began providing natural gas supply management services to our utility operations in a limited number of states. These services include aggregating and purchasing gas supply, arranging transportation and storage logistics and ultimately delivering the gas to our utility service areas at competitive prices.

The following summarizes our significant affiliate transactions with AEM, APS and AES.

	2006	2005	2004
	(In thousands, unless otherwise indicated)		
Gas purchases[1]:			
Dollars	$471,844	$227,315	$235,320
Volumes (Mcf)	52,554	31,370	42,518
Average sales price per Mcf	$ 8.98	$ 7.25	$ 5.53
Storage contract fees	$ 1,792	$ 1,753	$ 2,765
Natural gas management services	$ 3,573	$ 2,986	$ 682

[1] Gas purchases are made in a competitive bidding process, reflect market prices and exclude demand and other charges.

JD Woodward was Senior Vice President, Nonutility Operations of the Company from April 2001 to April 2006. Woodward Marketing L.L.C., a wholly-owned subsidiary of the Company through September 30, 2003 and its successor, AEM, leased office space from one corporation owned by Mr. Woodward. The lease originated in April 2002 and was terminated in July 2006.

During 2006, 2005 and 2004, our utility division leased office space and vehicles from our natural gas marketing and other nonutility segments. Base lease payments were $1.1 million, $1.0 million and $1.2 million in 2006, 2005 and 2004.

19. Selected Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data is presented below. The sum of net income per share by quarter may not equal the net income per share for the year due to variations in the weighted average shares outstanding used in computing such amounts. Our businesses are seasonal due to weather conditions in our service areas. For further information on its effects on quarterly results, see the "Results of Operations" discussion included in the "Management's Discussion and Analysis of Financial Condition and Results of Operations" section herein.

	Quarter Ended			
	December 31	March 31	June 30	September 30
	(In thousands, except per share data)			
Fiscal year 2006:				
Operating revenues				
Utility segment	$1,405,010	$1,447,620	$ 402,044	$ 395,917
Natural gas marketing segment	1,101,845	818,629	562,447	673,603
Pipeline and storage segment	39,712	45,483	35,862	39,510
Other nonutility segment	1,492	1,595	1,413	1,398
Intersegment eliminations	(264,239)	(279,481)	(138,523)	(138,974)
	2,283,820	2,033,846	863,243	971,454
Gross profit	346,590	405,403	204,500	260,077
Operating income	149,697	180,833	4,803	47,283
Net income (loss)	71,027	88,796	(18,145)	6,059
Net income (loss) per basic share	$ 0.88	$ 1.10	$ (0.22)	$ 0.07
Net income (loss) per diluted share	$ 0.88	$ 1.10	$ (0.22)	$ 0.07
Fiscal year 2005:				
Operating revenues				
Utility segment	$ 913,681	$1,235,377	$ 501,735	$ 452,347
Natural gas marketing segment	493,801	512,891	466,835	632,751
Pipeline and storage segment	43,690	45,546	33,449	30,604
Other nonutility segment	1,359	1,278	1,421	1,244
Intersegment eliminations	(83,907)	(110,007)	(96,563)	(115,659)
	1,368,624	1,685,085	906,877	1,001,287
Gross profit	322,103	375,894	221,274	198,366
Operating income	128,674	172,181	39,468	8,332
Net income (loss)	59,599	88,502	4,486	(16,802)
Net income (loss) per basic share	$ 0.79	$ 1.12	$ 0.06	$ (0.21)
Net income (loss) per diluted share	$ 0.79	$ 1.11	$ 0.06	$ (0.21)

ITEM 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

ITEM 9A. ***Controls and Procedures***

Management's Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures that are designed to provide reasonable assurance that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit to the United States Securities and Exchange Commission under the Securities and Exchange Act of 1934, as amended (the "Act"), is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms. Under the supervision and with the participation of our management, including our Chairman, President and Chief Executive Officer ("Principal Executive Officer") and our Senior Vice President and Chief Financial Officer ("Principal Financial Officer"), we evaluated the effectiveness of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Act. 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 ensuring that information required to be disclosed by us in this annual report on Form 10-K was accumulated and communicated to our management, including our Principal Executive and Principal Financial Officers, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f), in providing reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation under the framework in *Internal Control-Integrated Framework* issued by COSO and applicable Securities and Exchange Commission rules, our management concluded that our internal control over financial reporting was effective as of September 30, 2006.

Ernst & Young LLP has issued its report on management's assessment and on the effectiveness of the Company's internal control over financial reporting. That report appears below.

/s/ ROBERT W. BEST
Robert W. Best
Chairman, President and Chief Executive Officer

/s/ JOHN P. REDDY
John P. Reddy
Senior Vice President and Chief Financial Officer

November 20, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The Board of Directors
Atmos Energy Corporation

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that Atmos Energy Corporation maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Atmos Energy Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Atmos Energy Corporation maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Atmos Energy Corporation maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atmos Energy Corporation as of September 30, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended September 30, 2006 of Atmos Energy Corporation and our report dated November 20, 2006 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Dallas, Texas
November 20, 2006

Changes in Internal Control over Financial Reporting

We did not make any changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and 15d-15(f) under the Act) during the fourth quarter of the fiscal year ended September 30, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. ***Other Information***

Not applicable.

PART III

ITEM 10. ***Directors and Executive Officers of the Registrant***

Information regarding directors and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007. Information regarding executive officers is included in Part I of this Form 10-K.

Identification of the members of the Audit Committee of the Board of Directors as well as the Board of Directors' determination as to whether one or more audit committee financial experts are serving on the Audit Committee of the Board of Directors is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

The Company has adopted a code of ethics for its principal executive officer, principal financial officer and principal accounting officer. Such code of ethics is represented by the Company's Code of Conduct, which is applicable to all directors, officers and employees of the Company, including the Company's principal executive officer, principal financial officer and principal accounting officer. A copy of the Company's Code of Conduct is posted on the Company's website at *www.atmosenergy.com* under "Corporate Governance". In addition, any amendment to or waiver granted from a provision of the Company's Code of Conduct will be posted on the Company's website under "Corporate Governance".

ITEM 11. ***Executive Compensation***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

ITEM 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Security ownership of certain beneficial owners and of management is incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007. Information concerning our equity compensation plans is provided in Part II, Item 5, Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, of this Annual Report on Form 10-K.

ITEM 13. ***Certain Relationships and Related Transactions***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

ITEM 14. ***Principal Accountant Fees and Services***

Incorporated herein by reference from the Company's Definitive Proxy Statement for the Annual Meeting of Shareholders on February 7, 2007.

PART IV

ITEM 15. ***Exhibits and Financial Statement Schedules***

(a) 1. and 2. *Financial statements and financial statement schedules.*

The financial statements and financial statement schedule listed in the Index to Financial Statements in Item 8 are filed as part of this Form 10-K.

3. *Exhibits*

The exhibits listed in the accompanying Exhibits Index are filed as part of this Form 10-K. The exhibits numbered 10.7(a) through 10.16(e) are management contracts or compensatory plans or arrangements.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

ATMOS ENERGY CORPORATION
(Registrant)

By: /s/ JOHN P. REDDY
John P. Reddy
Senior Vice President
and Chief Financial Officer

Date: November 22, 2006

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS, that each person whose signature appears below hereby constitutes and appoints Robert W. Best and John P. Reddy, or either of them acting alone or together, as his true and lawful attorney-in-fact and agent with full power to act alone, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Form 10-K, and to file the same, with all exhibits thereto, and all other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorney-in-fact and agent full power and authority to do and perform each and every act and thing requisite and necessary to be done in and about the premises, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorney-in-fact and agent, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the date indicated:

/s/ ROBERT W. BEST Robert W. Best	Chairman, President and Chief Executive Officer	November 22, 2006
/s/ JOHN P. REDDY John P. Reddy	Senior Vice President and Chief Financial Officer	November 22, 2006
/s/ F. E. MEISENHEIMER F. E. Meisenheimer	Vice President and Controller (Principal Accounting Officer)	November 22, 2006
/s/ TRAVIS W. BAIN, II Travis W. Bain, II	Director	November 22, 2006
/s/ DAN BUSBEE Dan Busbee	Director	November 22, 2006
/s/ RICHARD W. CARDIN Richard W. Cardin	Director	November 22, 2006
/s/ THOMAS J. GARLAND Thomas J. Garland	Director	November 22, 2006
/s/ RICHARD K. GORDON Richard K. Gordon	Director	November 22, 2006
/s/ GENE C. KOONCE Gene C. Koonce	Director	November 22, 2006

/s/ THOMAS C. MEREDITH Thomas C. Meredith	Director	November 22, 2006
/s/ PHILLIP E. NICHOL Phillip E. Nichol	Director	November 22, 2006
/s/ NANCY K. QUINN Nancy K. Quinn	Director	November 22, 2006
/s/ STEPHEN R. SPRINGER Stephen R. Springer	Director	November 22, 2006
/s/ CHARLES K. VAUGHAN Charles K. Vaughan	Director	November 22, 2006
/s/ RICHARD WARE II Richard Ware II	Director	November 22, 2006

Schedule II

ATMOS ENERGY CORPORATION

Valuation and Qualifying Accounts
Three Years Ended September 30, 2006

	Balance at Beginning of Period	Additions: Charged to Cost & Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
			(In thousands)		
2006					
Allowance for doubtful accounts	$ 15,613	$ 21,819	$ —	$ 23,746[2]	$ 13,686
2005					
Allowance for doubtful accounts	$ 7,214	$ 20,293	$4,563[1]	$ 16,457[2]	$ 15,613
2004					
Allowance for doubtful accounts	$ 13,051	$ 5,379	$ —	$ 11,216[2]	$ 7,214

[1] Represents allowance for doubtful accounts recorded in connection with the TXU Gas acquisition.

[2] Uncollectible accounts written off.

EXHIBITS INDEX
Item 14.(a)(3)

Exhibit Number	Description	Page Number or Incorporation by Reference to
	Plan of Reorganization	
2.1(a)	Agreement and Plan of Merger and Reorganization dated as of September 21, 2001, by and among Atmos Energy Corporation, Mississippi Valley Gas Company and the Shareholders Named on the Signature Pages hereto	Exhibit 2.2 to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
2.1(b)	Agreement and Plan of Merger by and between TXU Gas Company and LSG Acquisition Corporation dated June 17, 2004	Exhibit 2.1 to Form 8-K dated June 17, 2004 (File No. 1-10042)
2.1(c)	Amendment No. 1 to Merger Agreement, dated as of September 30, 2004, by and between LSG Acquisition Corporation and TXU Gas Company LP	Exhibit 2.1 to Form 8-K dated September 30, 2004 (File No. 1-10042)
	Articles of Incorporation and Bylaws	
3.1	Amended and Restated Articles of Incorporation of Atmos Energy Corporation (as of February 9, 2005)	Exhibit 3(I) to Form 10-Q dated March 31, 2005 (File No. 1-10042)
3.2	Amended and Restated Bylaws of Atmos Energy Corporation (as of August 13, 2003)	Exhibit 4.2 to Form S-3 dated August 31, 2004 (File No. 333-118706)
	Instruments Defining Rights of Security Holders	
4.1	Specimen Common Stock Certificate (Atmos Energy Corporation)	Exhibit (4)(b) to Form 10-K for fiscal year ended September 30, 1988 (File No. 1-10042)
4.2	Rights Agreement, dated as of November 12, 1997, between the Company and BankBoston, N.A., as Rights Agent	Exhibit 4.1 to Form 8-K dated November 12, 1997 (File No. 1-10042)
4.3	First Amendment to Rights Agreement dated as of August 11, 1999, between the Company and BankBoston, N.A., as Rights Agent	Exhibit 2 to Form 8-A, Amendment No. 1, dated August 12, 1999 (File No. 1-10042)
4.4	Second Amendment to Rights Agreement dated as of February 13, 2002, between the Company and EquiServe Trust Company, N.A., fka BankBoston, N.A., as Rights Agent	Exhibit 4 to Form 10-Q for quarter ended December 31, 2001 (File No. 1-10042)
4.5	Registration Rights Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company	Exhibit 99.2 to Form 8-K/A, dated December 3, 2002 (File No. 1-10042)
4.6	Standstill Agreement, dated as of December 3, 2002, by and among Atmos Energy Corporation and the Shareholders of Mississippi Valley Gas Company	Exhibit 99.3 to Form 8-K/A, dated December 3, 2002 (File No. 1-10042)
4.7	Indenture dated as of July 15, 1998 between Atmos Energy Corporation and U.S. Bank Trust National Association, Trustee	Exhibit 4.8 to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.8	Indenture between Atmos Energy Corporation, as Issuer, and SunTrust Bank, Trustee dated as of May 22, 2001	Exhibit 99.3 to Form 8-K dated May 15, 2001 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
4.9(a)	Indenture of Mortgage, dated as of July 15, 1959, from United Cities Gas Company to First Trust of Illinois, National Association, and M.J. Kruger, as Trustees, as amended and supplemented through December 1, 1992 (the Indenture of Mortgage through the 20th Supplemental Indenture)	Exhibit to Registration Statement of United Cities Gas Company on Form S-3 (File No. 33-56983)
4.9(b)	Twenty-First Supplemental Indenture dated as of February 5, 1997 by and among United Cities Gas Company and Bank of America Illinois and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959	Exhibit 10.7(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
4.9(c)	Twenty-Second Supplemental Indenture dated as of July 29, 1997 by and among Atmos Energy Corporation and First Trust National Association and Russell C. Bergman supplementing Indenture of Mortgage dated as of July 15, 1959	Exhibit 4.10(c) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.10(a)	Indenture between United Cities Gas Company and Bank of America Illinois, as Trustee dated as of November 15, 1995	Exhibit 4.11(a) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.10(b)	First Supplemental Indenture between Atmos Energy Corporation and Bank of America Illinois, as Trustee dated as of July 29, 1997	Exhibit 4.11(b) to Form S-3 dated August 31, 2004 (File No. 333-118706)
4.11(a)	Debenture Certificate for the 6¾% Debentures due 2028	Exhibit 99.2 to Form 8-K dated July 22, 1998 (File No. 1-10042)
4.11(b)	Global Security for the 7⅜% Senior Notes due 2011	Exhibit 99.2 to Form 8-K dated May 15, 2001 (File No. 1-10042)
4.11(c)	Global Security for the 5⅛% Senior Notes due 2013	Exhibit 10(2)(c) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.11(d)	Global Security for the Floating Rate Senior Notes due 2007	Exhibit 10(2)(d) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.11(e)	Global Security for the 4.00% Senior Notes due 2009	Exhibit 10(2)(e) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.11(f)	Global Security for the 4.95% Senior Notes due 2014	Exhibit 10(2)(f) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
4.11(g)	Global Security for the 5.95% Senior Notes due 2034	Exhibit 10(2)(g) to Form 10-K for the year ended September 30, 2004 (File No. 1-10042)
	Material Contracts	
10.1	Guaranty of Atmos Energy Corporation dated June 17, 2004	Exhibit 10.2 to Form 8-K dated June 17, 2004 (File No. 1-10042)
10.2(a)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Gas Company LP	Exhibit 10.1 to Form 8-K dated September 30, 2004 (File No. 1-10042)
10.2(b)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation, Oncor Utility Solutions (Texas) Company and TXU Electric Delivery Company	Exhibit 10.2 to Form 8-K dated September 30, 2004 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.2(c)	Transitional Services Agreement, dated as of October 1, 2004, by and between Atmos Energy Corporation and TXU Business Services Company (Exhibit A to Schedule 2 containing listing of employee credit and procurement cards is omitted, to be supplementally furnished to the Commission upon request)	Exhibit 10.3 to Form 8-K dated September 30, 2004 (File No. 1-10042)
10.2(d)	Transitional Access Agreement, dated as of October 1, 2004, by and among Atmos Energy Corporation and TXU Energy Retail Company LP, TXU Business Services Company, TXU Properties Company and TXU Electric Delivery Company	Exhibit 10.4 to Form 8-K dated September 30, 2004 (File No. 1-10042)
10.3	Revolving Credit Agreement (3 Year Facility), dated as of October 18, 2005, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent and Bank of America, N.A., Wachovia Bank, National Association and Societe Generale, as Co-Documentation Agents, and the lenders from time to time parties thereto	Exhibit 10.1 to Form 8-K dated October 18, 2005 (File No. 1-10042)
10.4	Pipeline Construction and Operating Agreement, dated November 30, 2005, by and between Atmos-Pipeline Texas, a division of Atmos Energy Corporation, a Texas and Virginia corporation and Energy Transfer Fuel, LP, a Delaware limited partnership	Exhibit 10.1 to Form 8-K dated November 30, 2005 (File No. 1-10042)
10.5(a)	Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas and the other financial institutions which may become parties thereto.	Exhibit 10.1 to Form 8-K dated March 30, 2005 (File No. 1-10042)
10.5(b)	First Amendment, dated as of November 28, 2005, to the Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Société Générale, and the other financial institutions which may become parties thereto.	Exhibit 10.1 to Form 8-K dated November 28, 2005 (File No. 1-10042)
10.5(c)	Second Amendment, dated as of March 31, 2006, to the Uncommitted Second Amended and Restated Credit Agreement, dated to be effective March 30, 2005, among Atmos Energy Marketing, LLC, Fortis Capital Corp., BNP Paribas, Société Générale and the other financial institutions which may become parties thereto	Exhibit 10.1 to Form 8-K dated March 31, 2006 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.6	Revolving Credit Agreement (364 Day Facility), dated as of November 7, 2006, among Atmos Energy Corporation, SunTrust Bank, as Administrative Agent, Wachovia Bank, N.A., as Syndication Agent and Bank of America, N.A., JPMorgan Chase Bank, N.A., and the Royal Bank of Scotland, Plc as Co-Documentation Agents, and the lenders from time to time parties thereto	Exhibit 10.1 to Form 8-K dated November 7, 2006 (File No. 1-10042)
	Executive Compensation Plans and Arrangements	
10.7(a)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier I	Exhibit 10.21(b) to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.7(b)*	Form of Amendment No. One to the Atmos Energy Corporation Change in Control Severance Agreement, Tier I	Exhibit 10.1 to Form 8-K dated May 9, 2006 (File No. 1-10042)
10.7(c)*	Form of Atmos Energy Corporation Change in Control Severance Agreement — Tier II	Exhibit 10.21(c) to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.7(d)*	Form of Amendment No. One to the Atmos Energy Corporation Change in Control Severance Agreement, Tier II	Exhibit 10.2 to Form 8-K dated May 9, 2006 (File No. 1-10042)
10.8*	Atmos Energy Corporation Long-Term Stock Plan for the United Cities Gas Company Division	Exhibit 99.1 to Form S-8 filed July 29, 1997 (File No. 333-32343)
10.9(a)*	Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.9(b)*	Amendment No. 1 to the Atmos Energy Corporation Executive Retiree Life Plan	Exhibit 10.31(a) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.10(a)*	Description of Financial and Estate Planning Program	Exhibit 10.25(b) to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.10(b)*	Description of Sporting Events Program	Exhibit 10.26(c) to Form 10-K for fiscal year ended September 30, 1993 (File No. 1-10042)
10.11(a)*	Atmos Energy Corporation Supplemental Executive Benefits Plan, Amended and Restated in its Entirety August 12, 1998	Exhibit 10.26 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.11(b)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date August 12, 1998	Exhibit 10.32 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)
10.11(c)*	Amendment No. One to the Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan, Effective Date January 1, 1999	Exhibit 10.2 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.11(d)*	Atmos Energy Corporation Performance-Based Supplemental Executive Benefits Plan Trust Agreement, Effective Date December 1, 2000	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.11(e)*	Form of Individual Trust Agreement for the Supplemental Executive Benefits Plan	Exhibit 10.3 to Form 10-Q for quarter ended December 31, 2000 (File No. 1-10042)
10.12*	Atmos Energy Corporation Executive Nonqualified Deferred Compensation Plan	Exhibit 10.33 to Form 10-K for fiscal year ended September 30, 1998 (File No. 1-10042)

Exhibit Number	Description	Page Number or Incorporation by Reference to
10.13(a)*	Mini-Med/Dental Benefit Extension Agreement dated October 1, 1994	Exhibit 10.28(f) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.13(b)*	Amendment No. 1 to Mini-Med/Dental Benefit Extension Agreement dated August 14, 2001	Exhibit 10.28(g) to Form 10-K for fiscal year ended September 30, 2001 (File No. 1-10042)
10.13(c)*	Amendment No. 2 to Mini-Med/Dental Benefit Extension Agreement dated December 31, 2002	Exhibit 10.1 to Form 10-Q for quarter ended December 31, 2002 (File No. 1-10042)
10.14*	Atmos Energy Corporation Equity Incentive and Deferred Compensation Plan for Non-Employee Directors	Exhibit C to Definitive Proxy Statement on Schedule 14A filed December 30, 1998 (File No. 1-10042)
10.15*	Atmos Energy Corporation Outside Directors Stock-for-Fee Plan (Amended and Restated as of November 12, 1997)	Exhibit 10.28 to Form 10-K for fiscal year ended September 30, 1997 (File No. 1-10042)
10.16(a)*	Atmos Energy Corporation 1998 Long-Term Incentive Plan (as amended and restated February 14, 2002)	Exhibit 10.1 to Form 10-Q for quarter ended March 31, 2002 (File No. 1-10042)
10.16(b)*	Form of Non-Qualified Stock Option Agreement under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(b) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.16(c)*	Form of Award Agreement of Restricted Stock With Time-Lapse Vesting under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(c) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.16(d)*	Form of Award Agreement of Performance-Based Restricted Stock Units under the Atmos Energy Corporation 1998 Long-Term Incentive Plan	Exhibit 10.16(d) to Form 10-K for fiscal year ended September 30, 2005 (File No. 1-10042)
10.16(e)*	Atmos Energy Corporation Annual Incentive Plan for Management (as amended and restated February 14, 2002)	Exhibit 10.2 to Form 10-Q for quarter ended March 31, 2002 (File No. 1-10042)
12	Statement of computation of ratio of earnings to fixed charges	
	Other Exhibits, as indicated	
21	Subsidiaries of the registrant	
23	Consent of independent registered public accounting firm, Ernst & Young LLP	
24	Power of Attorney	Signature page of Form 10-K for fiscal year ended September 30, 2006
31	Rule 13a-14(a)/15d-14(a) Certifications	
32	Section 1350 Certifications **	
99	Annual Certification Pursuant to Section 303A.12 of the New York Stock Exchange Listed Company Manual	

* This exhibit constitutes a "management contract or compensatory plan, contract, or arrangement."

** These certifications pursuant to 18 U.S.C. Section 1350 by the Company's Chief Executive Officer and Chief Financial Officer, furnished as Exhibit 32 to this Annual Report on Form 10-K, will not be deemed to be filed with the Securities and Exchange Commission or incorporated by reference into any filing by the Company under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent that the Company specifically incorporates such certifications by reference.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR 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 1-8359

NEW JERSEY RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

New Jersey	**22-2376465**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)
1415 Wyckoff Road, Wall, New Jersey 07719	**732-938-1480**
(Address of principal executive offices)	(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12 (b) of the Act:

Common Stock - $2.50 Par Value	**New York Stock Exchange**
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12 (g) of the Act:

None

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer: ☒ **Accelerated filer:** ☐ **Non-accelerated filer:** ☐

The aggregate market value of the Registrant's Common Stock held by nonaffiliates was $1,253,111,780 based on the closing price of $45.25 per share on March 31, 2006.

The number of shares outstanding of $2 . 50 par value Common Stock as of November 20, 2006 was 27,678,310.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive Proxy Statement for the Annual Meeting of Shareowners to be held January 24, 2007, to be filed on or about December 22, 2006, are incorporated by reference into Part I and Part III of this report.

New Jersey Resources

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INFORMATION CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements contained in this report, including, without limitation, statements as to management expectations and beliefs presented in Item 1.—Business, under the captions "Natural Gas Distribution—General;—Gas Supply;—Regulation and Rates"; and "Environment," and in Item 3.—"Legal Proceedings," and in Part II including "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7, and "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements can also be identified by the use of forward-looking terminology such as "may," "intend," "expect," "believe" or "continue" or comparable terminology and are made based upon management's expectations and beliefs concerning future developments and their potential effect upon New Jersey Resources Corporation (NJR or the Company). There can be no assurance that future developments will be in accordance with management's expectations or that the effect of future developments on the Company will be those anticipated by management.

The Company cautions readers that the assumptions that form the basis for forward-looking statements regarding customer growth, customer usage, financial condition, results of operations, cash flows, capital requirements, market risk and other matters for fiscal 2007 and thereafter include many factors that are beyond the Company's ability to control or estimate precisely, such as estimates of future market conditions, the behavior of other market participants and changes in the debt and equity capital markets. The factors that could cause actual results to differ materially from NJR's expectations include, but are not limited to those discussed in Risk Factors in Item 1A, as well as the following:

- weather and economic conditions;
- demographic changes in the New Jersey Natural Gas (NJNG) service territory;
- the rate of NJNG customer growth;
- volatility of natural gas commodity prices and its impact on customer usage, NJR Energy Services' (NJRES) operations and on the Company's risk management efforts;
- changes in rating agency requirements and/or credit ratings and their effect on availability and cost of capital to the Company;
- commercial and wholesale credit risks, including creditworthiness of customers and counterparties;
- the impact of governmental regulation (including the regulation of rates);
- fluctuations in energy-related commodity prices;
- conversion activity and other marketing efforts;
- actual energy usage of NJNG's customers;
- the pace of deregulation of retail gas markets;
- access to adequate supplies of natural gas;
- the regulatory and pricing policies of federal and state regulatory agencies;
- changes due to legislation at the federal and state level;
- the availability of an adequate number of appropriate counterparties in the wholesale energy trading market;

- sufficient liquidity in the wholesale energy trading market and continued access to the capital markets;
- the disallowance of recovery of environmental-related expenditures and other regulatory changes;
- environmental-related and other litigation;
- the effects and impacts of inflation on NJR and its subsidiaries operations;
- change in accounting pronouncements issued by the appropriate standard setting bodies; and
- terrorist attacks or threatened attacks on energy facilities or unrelated energy companies.

While the Company periodically reassesses material trends and uncertainties affecting the Company's results of operations and financial condition in connection with its preparation of management's discussion and analysis of results of operations and financial condition contained in its Quarterly and Annual Reports, the Company does not, by including this statement, assume any obligation to review or revise any particular forward-looking statement referenced herein in light of future events.

ITEM 1. BUSINESS

ORGANIZATIONAL STRUCTURE

New Jersey Resources Corporation (NJR or the Company) is a New Jersey corporation formed in 1982 pursuant to a corporate reorganization. The Company is an energy services holding company providing retail and wholesale energy services to customers in New Jersey, in states from the Gulf Coast to New England, and Canada. The Company is an exempt holding company under section 1263 of the Energy Policy Act of 2005. NJR's subsidiaries and businesses include:

1) New Jersey Natural Gas (NJNG), a local natural gas distribution company that provides regulated retail natural gas service to approximately 471,000 residential and commercial customers in central and northern New Jersey and participates in the off-system sales and capacity release markets. NJNG is regulated by the New Jersey Board of Public Utilities (BPU) and comprises the Company's Natural Gas Distribution segment.

2) NJR Energy Services (NJRES) is the Company's principal non-utility subsidiary. It maintains and trades around a portfolio of physical assets consisting of natural gas storage and transportation contracts. As well, NJRES provides wholesale energy management services to other energy companies. NJRES comprises the Company's Energy Services segment.

3) The Company also has a Retail and Other operations segment, which includes the following companies:

   a.) NJR Retail Holdings (Retail Holdings), formed in November 2001 as an unregulated affiliate to consolidate the Company's unregulated retail operations. Retail Holdings includes the operations of NJR Home Services (NJRHS), a company formed in August 1998 to provide heating ventilation and cooling (HVAC) service repair and contract services.

   b.) NJR Capital Services (Capital), formed as an unregulated affiliate to consolidate the Company's unregulated energy-related and real estate investments. Capital includes the following wholly owned subsidiaries:

   Commercial Realty & Resources (CR&R), a company formed in May 1966, which holds and develops commercial real estate.

   NJR Investment, a company formed in October 2000 to make certain energy-related equity investments.

   NJR Energy Holdings, including NJR Energy, which invests primarily in energy-related ventures through its subsidiary, NJNR Pipeline (Pipeline) which holds the Company's 5.53 percent interest in Iroquois Gas and Transmission System, LP (Iroquois).

   c.) NJR Service (Service), an unregulated company formed in August 2000 as a wholly owned subsidiary of NJR to provide shared administrative services, including corporate communications, financial and administrative, internal audit, legal, human resources and technology for NJR and all subsidiaries of NJR.

ITEM 1. BUSINESS (Continued)

BUSINESS SEGMENTS

The Company operates within three primary business segments: Natural Gas Distribution, Energy Services and Retail and Other.

The Natural Gas Distribution segment consists of regulated energy and off-system, capacity and storage management operations. The Energy Services segment consists of unregulated wholesale energy operations. The Retail and Other segment consists of appliance repair, sales and installation services, commercial real estate development, investment and other corporate activities.

NATURAL GAS DISTRIBUTION

General

NJNG provides natural gas service to approximately 471,000 customers. Its service territory encompasses 1,436 square miles, covering 104 municipalities with an estimated population of 1.3 million people.

NJNG's service territory is in New Jersey's Monmouth and Ocean counties and parts of Morris and Middlesex counties. It is primarily suburban, with a wide range of cultural and recreational activities and highlighted by approximately 100 miles of New Jersey seacoast. It is in proximity to New York City, Philadelphia and the metropolitan areas of northern New Jersey and is accessible through a network of major roadways and mass transportation. NJNG added 10,159 and 10,435 new customers and added natural gas heat and other services to another 874 and 929 existing customers in fiscal 2006 and 2005, respectively. This annual growth rate of approximately 2.2 percent is expected to continue with projected additions of approximately 20,300 new customers over the next two years. This growth would represent an annual increase of approximately 1.5 billion cubic feet (Bcf) in sales to firm customers and approximately $4.8 million in new utility gross margin, as calculated under NJNG's Conservation Incentive Program (CIP) tariff, which became effective October 1, 2006.

In assessing the potential for future growth in its service area, NJNG uses information derived from county and municipal planning boards which describes housing developments in various stages of approval. Furthermore, builders in NJNG's service area are surveyed to determine development plans for future time periods. NJNG has also periodically engaged outside consultants to assist in its customer growth projections. In addition to customer growth through new construction, NJNG's business strategy includes aggressively pursuing conversions from other fuels, such as electricity and oil. It is estimated that approximately 32 percent of NJNG's projected customer growth will consist of conversions. NJNG will also continue to pursue off-system sales and nonpeak sales.

ITEM 1. BUSINESS (Continued)

Throughput

For the fiscal year ended September 30, 2006, operating revenues and throughput by customer class were as follows:

	Operating Revenues (Thousands)		Throughput (Bcf)	
Residential	$ 598,274	53%	39.4	39%
Commercial and other	172,465	15	10.4	10
Firm transportation	28,656	2	7.4	7
Total residential and commercial	**799,395**	**70**	**57.2**	**56**
Interruptible	12,134	1	7.2	7
Total system	**811,529**	**71**	**64.4**	**63**
Incentive programs	327,245	29	38.4	37
Total	**$ 1,138,774**	**100%**	**102.8**	**100%**

In fiscal 2006, no single customer represented more than 10 percent of total NJNG operating revenue.

Seasonality of Gas Revenues

As a result of the heat-sensitive nature of NJNG's residential customer base, therm sales are significantly affected by weather conditions. Specifically, customer demand substantially increases during the winter months when natural gas is used for heating purposes. Weather conditions directly influence the volume of natural gas delivered. The relative measurement of the impact of weather is in degree days. Degree-data is used to estimate amounts of energy required to maintain comfortable indoor temperature levels based on each day's average temperature. A degree-day is the measure of the variation in the weather based on the extent to which the average daily temperature falls below 65 degrees Fahrenheit. Each degree of temperature below 65 degrees Fahrenheit is counted as one heating degree day. Normal heating degree-days are based on a 20 year average, calculated based upon three reference areas representative of NJNG's service territory.

For reporting periods though September 30, 2006, the impact of weather on the level and timing of NJNG's revenues, gross margin and cash flows had been affected by a weather-normalization clause (WNC), which provided for a revenue adjustment if the weather varied by more than one-half of 1 percent from normal. However, the WNC did not capture declines in customer usage. The accumulated adjustment from one heating season (i.e., October-May) was billed or credited to customers in subsequent periods.

Beginning in October 2006, NJNG's revenues, gross margin and cash flows will be affected by the CIP, which decouples the link between customer usage and NJNG's utility gross margin, allowing NJNG to encourage its customers to conserve energy. During the three-year term of the pilot, the existing WNC would be suspended and replaced with the CIP tracking mechanism, which addresses utility gross margin variations related to both weather and customer usage . Recovery of such utility gross margin is subject to additional conditions including an earnings test and an evaluation of Basic Gas Supply Service (BGSS)-related savings achieved. Under the CIP agreement, if NJNG does not file

for a rate review with the BPU within two years, the return on equity for the earnings test will decline from 10.5 percent to 10.25 percent. For additional information regarding the CIP, see *Management's Discussion and Analysis—Natural Gas Distribution Operations* and *Note 4. Regulation* in the accompanying Consolidated Financial Statements.

Gas Supply

Firm Natural Gas Supplies

NJNG's gas supply portfolio consists of long-term (over seven months), winter-term (for the five winter months) and short-term contracts. In fiscal 2006, NJNG purchased gas from 92 suppliers under contracts ranging from one day to four years. In fiscal 2006, NJNG purchased approximately 10.2 percent of its natural gas from Alberta Northeast Gas Limited. No other supplier provided more than 10 percent of NJNG's natural gas supplies. NJNG believes the loss of any one or all of these suppliers would not have a material adverse impact on its results of operations, financial position or cash flows. NJNG believes that its supply strategy should adequately meet its expected firm load over the next several years.

Firm Transportation and Storage Capacity

In order to take delivery of firm natural gas supplies, which ensures the ability to reliably service its customers, NJNG maintains agreements for firm transportation and storage capacity with several interstate pipeline companies. NJNG receives natural gas at eight city gate stations located in Middlesex, Morris and Passaic counties in New Jersey.

The pipeline companies that provide firm transportation service to NJNG's city gate stations, the maximum daily deliverability of that capacity in dekatherms (dths) and the contract expiration dates are as follows:

Pipeline	Maximum daily deliverability (dths)	Expiration
Texas Eastern Transmission, L.P.	370,738	Various dates between 2007 and 2012
Iroquois Gas Transmission System, L.P.	20,468	2011
Tennessee Gas Pipeline Co.	35,894	Various dates between 2007 and 2008
Transcontinental Gas Pipe Line Corp.	22,531	Various dates between 2007 and 2014
Columbia Gas Transmission Corp.	10,000	2009
	459,631	

The pipeline companies that provide firm transportation service to NJNG and supply the above pipelines are ANR Pipeline Company, Tennessee Gas Pipeline, Dominion Transmission Corporation and Columbia Gulf Transmission Company.

1 1. BUSINESS (Continued)

In addition, NJNG has storage and related transportation contracts that provide additional maximum daily deliverability of 102,941 dths from storage fields in its Northeast market area. The storage suppliers, the maximum daily deliverability of that storage capacity and the contract expiration dates are as follows:

Pipeline	Maximum daily deliverability (dths)	Expiration
Texas Eastern Transmission, L.P.	94,557	Various dates between 2008 and 2010
Transcontinental Gas Pipe Line Corp.	8,384	2009
	102,941	

NJNG also has storage contracts, maximum daily deliverability and contract expiration dates as follows:

Company	Maximum daily deliverability (dths)	Expiration
ANR Pipeline Company	40,000	2007
Dominion Transmission Corporation (Dominion)	103,714	Various dates between 2011 and 2012
Central NY Oil & Gas (Stagecoach)	47,065	Various dates between 2007 and 2008
	190,779	

Both Dominion and Stagecoach utilize NJNG's transportation contracts to transport gas from their storage fields to NJNG's city gate.

Peaking Supply

To manage its winter peak day demand NJNG maintains two liquefied natural gas (LNG) facilities. See Item 2. *Properties–NJNG* for additional information regarding the LNG storage facilities. NJNG presently has LNG storage deliverability of 150,000 dths per day, which represents approximately 20 percent of its estimated peak day sendout.

Basic Gas Supply Service

Wholesale natural gas prices remain volatile. NJNG has mitigated the impact of these volatile price changes on customers through the use of hedging instruments, which are part of its financial risk management program, its storage incentive program and its BGSS clause. BGSS is a BPU-approved clause that requires all New Jersey natural gas utilities to make an annual filing by each June 1 for review of BGSS rates and to request a potential rate change to be effective the following October 1. The structure also allows each natural gas utility to provisionally increase residential and small commercial customer BGSS rates up to 5 percent on December 1 and February 1 on a self-implementing basis, after proper notice and BPU action on the June filing. Such increases are subject to subsequent BPU review and final approval. Decreases in the BGSS tariff can be implemented upon five days notice to the BPU.

On November 10, 2005, NJNG filed for a 23.2 percent price increase to an average residential customer, which was provisionally approved and became effective on December 14, 2005. This

increase was necessary due to higher wholesale natural gas prices and was subject to refund with interest.

During January and March 2006, NJNG filed supporting documentation with the BPU for a bill credit to its residential and small commercial sales customers for the period February 1, 2006 through April 30, 2006, as a result of lower wholesale natural gas prices. The bill credits, which temporarily reduced the BGSS tariff component, provided a benefit of approximately $28.6 million to NJNG's residential and small commercial customers during that period.

On June 1, 2006, NJNG filed for a reduction to the BGSS rate for residential and small commercial customers, due to the continued decrease in wholesale natural gas prices. The impact to the average residential sales customer's bill is a decrease of approximately 6.6 percent. This was approved by the BPU on a provisional basis on September 27, 2006. NJNG also credited approximately $22.5 million to residential and small commercial sales customers in September 2006.

On October 25, 2006, NJNG filed supporting documentation with the BPU for a self-implementing BGSS rate reduction to be effective November 1, 2006, which will lower residential and small commercial customers' bills by approximately 4 percent.

This decrease was initiated due to the continued reduction in wholesale natural gas prices subsequent to NJNG's November 10, 2005 BGSS filing.

Future Natural Gas Supplies

NJNG expects to meet the natural gas requirements for existing and projected firm customers into the foreseeable future. If NJNG's long-term natural gas requirements change, NJNG would renegotiate and restructure its contract portfolio components to better match the changing needs of its customers.

Regulation and Rates

NJNG is subject to the jurisdiction of the BPU with respect to a wide range of matters, such as rates, the issuance of securities, the adequacy of service, the manner of keeping its accounts and records, the sufficiency of natural gas supply, pipeline safety and the sale or encumbrance of its properties.

See *Note 4. Regulation* in the accompanying Consolidated Financial Statements for additional information regarding NJNG's rate proceedings.

Federal

The Federal Energy Regulatory Commission (FERC) regulates rates charged by interstate pipeline companies for the transportation and storage of natural gas. This affects NJNG's agreements for the purchase of such services with several interstate pipeline companies. Any costs associated with these services are recoverable through the BGSS.

ITEM 1. BUSINESS (Continued)

Competition

Although its franchises are nonexclusive, NJNG is not currently subject to competition from other natural gas distribution utilities with regard to the transportation of natural gas in its service territory. Due to significant distances between NJNG's current large industrial customers and the nearest interstate natural gas pipelines, as well as the availability of its transportation tariff, NJNG currently does not believe it has significant exposure to the risk that its distribution system will be bypassed. Competition does exist from suppliers of oil, coal, electricity and propane. At the present time, however, natural gas enjoys an advantage over alternate fuels in over 95 percent of new construction due to its efficiency and reliability. As deregulation of the natural gas industry continues, prices will be determined by market supply and demand but, although NJNG believes natural gas will remain competitive with alternate fuels, no assurance can be given in this regard.

In February 1999, the Electric Discount and Energy Competition Act (EDECA), which provides the framework for the restructuring of New Jersey's energy markets, became law. In March 2001, the BPU issued a written order that approved a stipulation agreement among various parties to fully open NJNG's residential markets to competition, restructure its rates to segregate its BGSS and delivery (i.e., transportation) prices as required by EDECA and expand an incentive for residential and small commercial customers to switch to transportation service. On September 30, 2006, NJNG had 8,594 residential and 4,280 commercial and industrial customers utilizing the transportation service. Based on its current and projected level of transportation customers, NJNG expects to use its existing firm transportation and storage capacity to fully meet its firm sales contract obligations.

In December 2000, the BPU issued a written order that resolved a customer account services proceeding. During the customer account services proceedings, the BPU noted that issues relating to the provision of services, such as metering and competitive billing, would be reviewed in the future. Based on the belief that there is little interest among third-party suppliers in competitive customer account services, the BPU staff recommended that further review be deferred until the competitive energy market is more fully developed.

In January 2002, the BPU issued an order stating that BGSS could be provided by suppliers other than the state's natural gas utilities, but BGSS should be provided by the state's natural gas utilities until further BPU action. No additional action has been taken by the BPU subsequent to its initial order in January 2002.

ENERGY SERVICES

NJRES provides unregulated wholesale energy services, including base load natural gas, peaking and balancing services, utilizing physical assets it controls, as well as asset management services to customers in states from the Gulf Coast and Mid-Continent to New England and Canada.

NJRES has built a portfolio of customers including local distribution companies, industrial companies, electric generators and retail aggregators. Sales to these customers have allowed NJRES to leverage its transportation and storage capacity and manage sales to these customers in an aggregate fashion. This strategy provides customers with better pricing and allows NJRES to extract more value from its portfolio of storage and transportation capacity. In addition, these customers have

ITEM 1. BUSINESS (Continued)

come to rely on NJRES' reliability, which is, in part, due to the ability to deliver from a firm supply source.

NJRES also focuses on creating value from underutilized natural gas assets, which are typically amassed through contractual rights to natural gas transportation and storage capacity. NJRES has developed a portfolio of storage and transportation capacity in the Northeast, Gulf Coast, Mid-Continent, Appalachia and Eastern Canada. These assets become more valuable when prices change between these areas and across time periods. NJRES seeks to optimize this process on a daily basis as market conditions change by evaluating all the natural gas supplies, transportation and opportunities to which it has access, to find the most profitable alternative for serving its various commitments. This enables NJRES to capture geographic pricing differences across these various regions as delivered natural gas prices change. NJRES' gross margin is defined as natural gas revenues and management fees less natural gas costs and fixed-demand costs.

In a similar manner, NJRES participates in natural gas storage transactions where it seeks to identify pricing differences that occur over time, as prices for future delivery periods at many locations are readily available. NJRES generates gross margin by locking in the differential between purchasing natural gas at the lowest current or future price and, in a related transaction, selling that natural gas at the highest current or future price, all within the constraints of its contracts and credit policies. Through the use of transportation and storage services, NJRES is able to generate gross margin through pricing differences that occur over the duration of time the assets are held.

NJRES' portfolio management customers include nonaffiliated utilities and electric generation plants. Services provided by NJRES include optimization of underutilized natural gas assets and basic gas supply functions. Revenue is customarily derived by a combination of a base service fee and incentive-based arrangements.

In fiscal 2006, NJRES had two customers, Hess Corporation and Washington Gas Light, who each represented more than 10 percent of its total revenue. Management believes that the loss of these customers would not have a material effect on its financial position, results of operations or cash flows as an adequate number of alternative counterparties exist.

Generally, NJRES' contracts are designated as a hedge for accounting purposes or meet the "normal purchase normal sale" scope tion of *Statement of Financial Accounting Standards (SFAS) No. 133 (as amended) "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133).* Under the normal purchase normal sale scope exception of SFAS 133 the commodity contract is accounted for under accrual accounting. For each commodity contract designated as a hedge for accounting purposes, the fair value of the effective portion of the hedge is deferred on the balance sheet and recognized in the income statement upon settlement of the hedged transaction. If the commodity contract does not meet the normal purchase normal sale scope exception of SFAS 133, or does not qualify as a hedge for accounting purposes, then it is recorded at fair value as a component of operating revenues.

ITEM 1. BUSINESS (Continued)

RETAIL AND OTHER

Retail and Other operations consist primarily of the following unregulated affiliates: NJRHS, which provides service, sales and installation of appliances; CR&R, which holds and develops commercial real estate; NJR Energy, an investor in energy-related ventures through its subsidiary, Pipeline, which consists primarily of its 5.53 percent equity investment in Iroquois, which is a 412-mile natural gas pipeline from the New York-Canadian border to Long Island, New York; NJR Investment, which makes certain energy-related equity investments; and Service Corp., which provides shared administrative services to the Company and all its subsidiaries.

As of September 30, 2006, CR&R's real estate portfolio consisted of 99 acres of undeveloped land in Monmouth and Atlantic counties and 5 acres of land currently being developed in Monmouth County. In fiscal 2005, CR&R changed its strategy with regard to its 52 acres of undeveloped land in Atlantic County. CR&R is seeking to sell, as opposed to developing, the land. In conjunction with this change in strategy, CR&R estimated its fair value and compared that to its book value. Accordingly, CR&R recognized a pre-tax impairment charge of $3.9 million in fiscal 2005. See *Note 1.–Impairment of Long-Lived Assets* in the accompanying Consolidated Financial Statements for a discussion of this change in strategy with regard to the Atlantic County land.

CR&R expects to sell approximately 15 acres of land in November 2006 for approximately $1.7 million, which would result in an anticipated pre-tax gain on sale of approximately $300,000. As this anticipated transaction will contain a lease-back provision with NJRHS of certain portions of buildings to be constructed on the acreage, it is expected that CR&R will recognize the pre-tax gain over the 10 year term of the lease.

CR&R's 32 acres of undeveloped land in Monmouth County will continue to be developed as market conditions allow.

See *Item 2. Properties–Retail and Other* for additional information regarding CR&R's remaining real estate assets.

ENVIRONMENT

The Company and its subsidiaries are subject to legislation and regulation by federal, state and local authorities with respect to environmental matters. The Company believes that it is in compliance in all material respects with all applicable environmental laws and regulations.

NJNG is responsible for environmental remediation at certain manufactured gas plant (MGP) sites which contain contaminated residues from former gas manufacturing operations that ceased at these sites by the mid-1950s and in some cases, had been discontinued many years earlier. NJNG is involved with environmental investigations and remedial actions at these MGP sites. In September 2006, with the assistance of an outside consulting firm, NJNG updated an environmental review of the MGP sites, including a review of potential liability for investigation and remedial action. Based on this review, NJNG estimated, at the time of the review, that exclusive of any insurance recoveries, total future expenditures to remediate and monitor the three MGP sites for which it is responsible, will range from $105.4 million to $174.6 million.

ITEM 1. BUSINESS (Continued)

NJNG's estimate of these liabilities is based upon known facts, existing technology and enacted laws and regulations in place when the review was completed. Where available information is sufficient to estimate the amount of the liability, it is NJNG's policy to accrue the full amount of such estimate. Where the information is sufficient only to establish a range of probable liability, and no point within the range is more likely than the other, it is NJNG's policy to accrue the lower end of the range. Accordingly, NJNG has recorded an MGP remediation liability and a corresponding Regulatory asset of $105.4 million on the Consolidated Balance Sheet, however, actual costs may differ from these estimates. NJNG will continue to seek recovery of these costs through its remediation rider, which is described in more detail in *Item 3 . Legal Proceedings* . See *Note 13 . Commitments and Contingent Liabilities* in the accompanying Consolidated Financial Statements for information with respect to environmental matters involving material expenditures for the remediation of the MGP sites.

See *Item 3. Legal Proceedings* for additional information regarding environmental activities.

CR&R is the owner of certain undeveloped land in Monmouth and Atlantic counties, New Jersey, with a net book value at September 30, 2006, of $9.6 million. This land is regulated by the provisions of the Freshwater Wetlands Protection Act (Wetlands Act), which restricts building in areas defined as "freshwater wetlands" and their transition areas. Based upon a third-party environmental engineer's delineation of the wetland and transition areas in accordance with the provisions of the Wetlands Act, CR&R will file for a Letter of Interpretation from the New Jersey Department of Environmental Protection (NJDEP) as parcels of land are selected for development. If the NJDEP reduces the amount of developable yield from CR&R's current estimates, a write-down of the carrying value of the undeveloped land may be required. Based upon the environmental engineer's revised estimated developable yield for undeveloped acreage, the Company does not believe that a write-down of the carrying value of the Monmouth County land was necessary as of September 30, 2006, because the estimated future cash flows from the development of the sites exceed the current investment in the sites.

Although the Company cannot estimate with certainty future costs of environmental compliance, which, among other factors, are subject to changes in technology and governmental regulations, the Company does not presently anticipate any additional significant future expenditure for compliance with existing environmental laws and regulations, other than for the remediation of the MGP sites discussed in *13. Commitments and Contingent Liabilities* in the accompanying Consolidated Financial Statements, which would have a material effect upon the capital expenditures, results of operations or competitive position of the Company or its subsidiaries.

EMPLOYEE RELATIONS

The Company and its subsidiaries had 766 and 770 employees at September 30, 2006 and 2005, respectively. NJNG had 370 and 373 union employees at September 30, 2006 and 2005, respectively. NJRHS had 84 and 90 union employees at September 30, 2006 and 2005, respectively. In December 2003, NJNG reached an agreement with Local 1820 of the International Brotherhood of Electrical Workers (IBEW), AFL-CIO, on a 5-year collective bargaining agreement which provides, among other things, for annual base wage increases of 3.25 percent, 3.5 percent, 3.5 percent, 3.75 percent and 4 percent, effective December 4, 2003, 2004, 2005, 2006 and 2007, respectively. In April 2003, NJRHS reached an agreement with the IBEW on a 4-year collective bargaining agreement

which provided, among other things, for an annual increase in base wages of 2.5 percent. The agreement also provided for annual increase in wages of 3 percent effective April 3, 2004, 2005 and 2006, with an additional 0.5 percent in "pay at risk" compensation if certain performance measures were met. The Company considers its relationship with employees, including those covered by collective bargaining agreements, to be good.

ITEM 1A. RISK FACTORS

When considering any investment in our securities, investors should consider the following information, as well as the information contained under the caption "Forward Looking Statements," in analyzing our present and future business performance. While this list is not exhaustive, our management also places no priority or likelihood based on their description or order of presentation.

Financial Risks

Ability to access the financial markets

NJR relies on access to both short-term and long-term credit as a significant source of liquidity for capital requirements not satisfied by its cash flow from operations. Any deterioration in NJR's financial condition could hamper its ability to access the credit markets or otherwise obtain debt financing. Because certain state regulatory approvals may be necessary in order for NJNG to incur debt, NJNG may not be able to access credit markets on a timely basis.

External events could also increase the cost of borrowing or adversely affect the ability to access the financial markets. Such external events could include the following:

- economic weakness in the United States or in the regions where NJR operates;
- financial difficulties of unrelated energy companies;
- capital market conditions generally;
- market prices for natural gas;
- the overall health of the natural gas utility industry; and
- fluctuations in interest rates.

Restrictions on the ability to access financial markets could affect management's ability to execute NJR's , NJRES' and NJNG's business plan. An inability to access capital may limit the ability to pursue improvements or acquisitions that NJR, or its subsidiaries, may otherwise rely on for future growth.

ITEM 1A. RISK FACTORS (Continued)

Credit rating downgrades could increase financing costs, limit access to the financial markets and negatively affect NJNG

The debt of NJNG is currently rated by the rating agencies Moody's Investor Services, Inc. and Standard & Poor's as investment grade. If such ratings are downgraded below investment grade, borrowing costs could increase, as will the costs of maintaining certain contractual relationships.

Lower credit ratings could also adversely affect relationships with state regulators, who may be unwilling to allow NJNG to pass along increased costs to its natural gas customers.

NJRES' ability to conduct its business is dependent upon the creditworthiness of NJR

If the ability of NJR to issue parental guarantees, or if NJR suffers a reduction in its credit and borrowing capacity, the business prospects of NJRES, which rely on the creditworthiness of NJR, would be adversely affected. NJRES would possibly be required to comply with various margin or other credit enhancement obligations under its trading and marketing contracts, and it may be unable to continue to trade or be able to do so only on less favorable terms with certain counterparties.

Debt covenants may impact financial condition if triggered

NJR and NJNG's long-term debt obligations contain financial covenants related to debt-to-capital ratios and interest coverage ratios. The failure to comply with any of these covenants could result in an event of default which, if not cured or waived, could result in the acceleration of outstanding debt obligations or the inability to borrow under certain credit agreements. Any such acceleration would cause a material adverse change in NJR or NJNG's financial condition.

An effective system of internal control is not maintained, leading to material weaknesses in internal control over financial reporting

Section 404 of the Sarbanes-Oxley Act of 2002 requires NJR's management to make an assessment of the design and effectiveness of internal controls. It also requires NJR's auditors to audit the design and effectiveness of these controls and to form an opinion on both management's assessment and the effectiveness of these controls. Management's ongoing assessment of these controls may identify areas of weakness in control design or effectiveness, which may lead to the conclusion that a material deficiency in internal control exists. NJR's auditors may also identify control deficiencies which may lead to identification of a material weakness in internal control. While NJR's system of internal controls is reviewed periodically, there exist inherent limitations to control effectiveness, including management override, collusion and lapses in judgment. Should NJR fail to maintain an effective system of internal controls leading to identification of a material weakness, NJR may not be able to produce reliable financial statements, which could result in a loss of investor confidence and a decline in its stock value. In addition, should NJR not be able to produce reliable financial statements, it could limit NJR's and NJNG's ability to access the capital markets.

ITEM 1A. RISK FACTORS (Continued)

Operational Risks

NJNG's operations are subject to certain operating risks

NJNG's operations are subject to all operating hazards and risks incidental to handling, storing, transporting and providing customers with natural gas, including explosions, pollution, release of toxic substances, fires, storms and other adverse weather conditions and hazards, each of which could result in damage to or destruction of facilities or damage to persons and property. If any of these events were to occur, NJR could suffer substantial losses. Moreover, as a result, NJR has been, and likely will be, a defendant in legal proceedings and litigation arising in the ordinary course of business. Although NJR maintains insurance coverage, insurance may not be sufficient to cover all material expenses related to these risks.

Major changes in the supply and price of natural gas may affect financial results

While NJNG expects to provide for the demand of its customers for the foreseeable future, factors impacting suppliers and other third parties including increased competition, further deregulation, transportation costs, transportation availability and drilling for new natural gas resources may impact the supply and price of natural gas. NJNG actively hedges against the fluctuation in the price of natural gas by entering into forward and financial contracts with third parties. Should these third parties fail to perform, it may result in a loss that could have a material impact on the financial position, cash flows and statement of operations of NJR.

NJNG and NJRES rely on third parties to supply natural gas

NJNG's ability to provide natural gas for its present and projected sales will depend upon its suppliers' ability to obtain and deliver additional supplies of natural gas, as well as NJNG's ability to acquire supplies directly from new sources. Factors beyond the control of NJNG, its suppliers and the independent suppliers who have obligations to provide natural gas to certain NJNG customers, may affect NJNG's ability to deliver such supplies. These factors include other parties' control over the drilling of new wells and the facilities to transport natural gas to NJNG's city gate stations, competition for the acquisition of natural gas, priority allocations, impact of severe weather disruptions to natural gas supplies, the regulatory and pricing policies of federal and state regulatory agencies, as well as the availability of Canadian reserves for export to the United States. Energy deregulation legislation may increase competition among natural gas utilities and impact the quantities of natural gas requirements needed for sales service.

NJRES also relies on a firm supply source to meet its energy management obligations for its customers. Should NJRES' suppliers fail to deliver supplies of natural gas, there could be a material impact on its cash flows and statement of operations.

The use of derivative contracts in the normal course of NJRES' business could result in financial losses that negatively impact results of operations

NJRES uses derivatives, including futures, forwards and swaps, to manage commodity and financial market risks. NJRES could recognize financial losses on these contracts as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under

ITEM 1A. RISK FACTORS (Continued)

a contract. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could adversely affect the value of the reported fair value of these contracts.

Inflation and increased natural gas costs could adversely impact NJNG's customer base and customer collections and increase its level of indebtedness

Inflation has caused increases in certain operating and capital costs. NJR has a process in place to continually review the adequacy of NJNG's rates in relation to the increasing cost of providing service and the inherent regulatory lag in adjusting those rates. The ability to control expenses is an important factor that will influence future results.

Rapid increases in the price of purchased gas may cause NJNG to experience a significant increase in short-term debt because it must pay suppliers for gas when it is purchased, which can be significantly in advance of when these costs may be recovered through the collection of monthly customer bills for gas delivered. Increases in purchased gas costs also slow collection efforts as customers are more likely to delay the payment of their gas bills, leading to higher-than-normal accounts receivable. This situation also results in higher short-term debt levels and increased bad debt expense.

Changes in weather conditions may affect earnings and cash flows

Weather conditions and other natural phenomena can have an adverse impact on earnings and cash flows. Severe weather conditions can impact suppliers and the pipelines that deliver gas to NJNG's distribution system. Extended mild weather, during either the winter period or summer period, can have a significant impact on demand for and the cost of natural gas. While NJR believes the CIP will mitigate the impact of weather on its gross margin, unusual weather conditions may still have an impact on its earnings. The CIP will not mitigate the impact of unusual weather conditions on its cash flows.

Changes in customer growth may affect earnings and cash flows

NJNG's ability to increase its utility firm gross margin is dependent upon the new construction housing market, as well as the additional conversion of customers to natural gas from other fuel sources. Should there be a slow down in these markets there could be an adverse impact on NJNG's utility firm gross margin, earnings and cash flow.

The cost of providing pension and postemployment health care benefits to eligible former employees is subject to changes in pension fund values and changing demographics and may have a material adverse effect on NJR's financial results

NJR has two defined benefit pension plans and two postemployment health care plans (OPEB) for the benefit of substantially all full-time employees and qualified retirees. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of

ITEM 1A. RISK FACTORS (Continued)

the pension and OPEB fund assets and changing demographics, including longer life expectancy of beneficiaries, an expected increase in the number of eligible former employees over the next five years and increases in health care costs.

Any sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of NJR's pension and OPEB funds. In these circumstances, NJR may be required to recognize an increased pension and OPEB expense or a charge to the statement of operations to the extent that the pension and OPEB fund values are less than the total anticipated liability under the plans.

NJRES' earnings and cash flows are dependent upon an asset optimization strategy of its physical assets with financial transactions

NJRES' earnings and cash flows are based, in part, on its ability to optimize its portfolio of contractual-based natural gas storage and pipeline assets. The optimization strategy involves utilizing its physical assets to take advantage of differences in natural gas prices between geographic locations and/or time periods. Any change among various pricing points could affect these differentials, which in turn could affect NJRES' earnings and cash flows.

NJRES is exposed to market risk and may incur losses in wholesale services

The commodity, storage and transportation portfolios at NJRES consist of contracts to buy and sell natural gas commodities, which are settled by physical delivery.

If the values of these contracts change in a direction or manner that NJRES does not anticipate, the value of NJRES' portfolio could be negatively impacted. NJRES employs a value at risk (VaR) model over these portfolios. VaR is defined as the largest likely potential loss in portfolio value. Based on a 95 percent confidence interval and employing a 1-day and a 10-day holding period for all positions, NJRES' portfolio of positions as of September 30, 2006 had a 1-day holding period VaR of $600,000 and 10-day holding period VaR of $2.5 million.

nting results may not be indicative of the risks NJRES is taking or the expected economic results due to changes in accounting for energy s, ies

Although NJRES enters into various contracts to hedge the value of its energy assets and operations, there can be no assurance that the hedge is operating effectively as intended and will continue to do so. Any uncontemplated change in the underlying item being hedged to that of a different or unforecasted position could result in a substantial negative impact to NJRES' and NJR's, financial condition, statement of operations or statement of cash flows.

NJNG and NJRES rely on storage and transportation assets that they do not own or control to deliver natural gas

NJNG and NJRES depend on natural gas pipelines and other storage and transportation facilities owned and operated by third parties to deliver natural gas to wholesale markets and to provide retail energy services to customers. If transportation is disrupted, or if storage capacity is inadequate, including for reasons of force majeure, the ability of NJNG and NJRES to sell and deliver their

ITEM 1A. RISK FACTORS (Continued)

products and services may be hindered. As a result, they may be responsible for damages incurred by their customers, such as the additional cost of acquiring alternative supply at then-current market rates.

Regulatory and Legal Risks

NJR is subject to governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits and certificates may result in substantial costs to NJR

NJR and its subsidiaries are subject to substantial regulation from federal, state and local regulatory authorities. They are required to comply with numerous laws and regulations and to obtain numerous authorizations, permits approvals and certificates from governmental agencies. These agencies regulate various aspects of their business, including customer rates, services and natural gas pipeline operations.

NJR and its subsidiaries cannot predict the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to them. Changes in regulations or the imposition of additional regulations could influence their operating environment and may result in substantial costs to them.

NJNG may not be able to recover amounts paid to plaintiffs as part of the Long Branch litigation settlement

As fully described in *Item 3. Legal Proceedings,* during fiscal 2006, NJNG reached a confidential settlement with plaintiffs surrounding claims alleging among other things, personal injury, wrongful death, property damage and claims for medical monitoring stemming from the operation and remediation of the former MGP site in Long Branch. NJNG requested that its insurer, Kemper Insurance Company (Kemper) defend and indemnify claims involving the Long Branch litigation and reimburse NJNG for remediation costs for the Long Branch site that exceed the self-insured retention. Although Kemper has not denied coverage, it has not yet reimbursed NJNG for any costs incurred to date. In October 2004, NJNG instituted suit for declaratory relief against Kemper and the matter is currently being litigated. Management believes that ion costs and the amounts paid pursuant to the settlement are recoverable through insurance and any liabilities not recoverable through ance, except for punitive and personal injury damages, would be recoverable, with BPU approval, through the remediation rider. However, there can be no assurance as to the ultimate resolution of the Kemper litigation, the recovery of these amounts or the impact of these matters on NJNG's financial condition, results of operations or cash flows.

Risks related to the regulation of NJNG could affect the rates it is able to charge, its costs and its profitability

NJNG is subject to regulation by federal, state and local authorities. These authorities regulate many aspects of NJNG's distribution operations, including construction and maintenance of facilities, operations, safety, rates that NJNG can charge customers, rates of return, the authorized cost of capital, recovery of pipeline replacement and environmental remediation costs and relationships with

ITEM 1A. RISK FACTORS (Continued)

its affiliates. NJNG's ability to obtain rate increases, extend its incentive programs and to maintain its current rates of return depends on regulatory discretion. There can be no assurance that NJNG will be able to obtain rate increases, continue its incentive programs or continue receiving its currently authorized rates of return.

Significant regulatory assets recorded by NJNG could be disallowed for recovery from customers in the future

NJNG records regulatory assets on its financial statements to reflect the rate-making nature and regulatory decision making of the BPU, as allowed by current accounting principles generally accepted in the United States of America. The creation of a regulatory asset allows for the deferral of costs that NJNG would normally, absent the recovery mechanism in rates approved by the BPU to charge its customers, charge to expense on its income statement. Primary regulatory assets that are subject to BPU approval include the underrecovery of BGSS and Universal Service Fund (USF) costs, remediation costs associated with its MGP sites, the WNC and the New Jersey Clean Energy program. If there were to be a change in regulatory position surrounding the collection of these deferred costs there could be a material impact on NJNG's financial position, operations and cash flows.

NJR's charter and bylaws may delay or prevent a transaction that stockholders would view as favorable

The certificate of incorporation and bylaws of NJR, as well as New Jersey law, contain provisions that could have the effect of delaying, deferring or preventing an unsolicited change in control of NJR, which may negatively affect the market price of the common stock or the ability of stockholders to participate in a transaction in which they might otherwise receive a premium for their shares over the then current market price. These provisions also may have the effect of preventing changes in management. In addition, the board of directors is authorized to issue preferred stock without stockholder approval on such terms as the board of directors may determine. The holders of common stock will be subject to, and may be negatively affected by, the rights of any preferred stock that may be issued in the future. In addition, NJR is subject to the New Jersey Shareholders' Protection Act, which could have the effect of delaying or preventing a change of control of NJR.

Environmental Risks

NJR costs of compliance with present and future environmental laws are significant and could adversely affect its cash flows and profitability

NJR's operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and site remediation. Compliance with these laws and regulations may require NJR to expend significant financial resources to, among other things, conduct site remediation and perform environmental monitoring. If NJR fails to comply with applicable environmental laws and regulations, even if it is unable to do so due to factors beyond its control, it may be subject to civil liabilities or criminal penalties and may be required to incur significant expenditures to come into compliance. Additionally, any alleged violations of environmental laws and regulations may require NJR to expend significant resources in its defense against alleged violations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

***NJNG* (All properties are located in New Jersey)**

NJNG owns approximately 6,500 miles of distribution main, 6,300 miles of service main, 210 miles of transmission main and approximately 483,000 meters. Mains are primarily located under public roads. Where mains are located under private property, NJNG has obtained easements from the owners of record.

Additionally, NJNG owns and operates two LNG storage plants in Stafford Township, Ocean County, and Howell Township, Monmouth County. The two LNG plants have an aggregate estimated maximum capacity of 150,000 dths per day. These facilities are used for peaking natural gas supply and emergencies.

NJNG owns four service centers located in Rockaway Township, Morris County; Atlantic Highlands and Wall Township, Monmouth County; and Lakewood, Ocean County. These service centers house storerooms, garages, gas distribution and administrative offices. NJNG leases its headquarters and customer service facilities in Wall Township, customer service offices in Asbury Park, Monmouth County, and a service center in Manahawkin, Ocean County. These customer service offices support customer contact, marketing, economic development and other functions.

Substantially all of NJNG's properties, not expressly excepted or duly released, are subject to the lien of an Indenture of Mortgage and Deed of Trust to BNY Midwest Trust Company, Chicago, Illinois, dated April 1, 1952, as amended by 31 supplemental indentures (Indenture), as security for NJNG's bonded debt, which totaled approximately $195 million at September 30, 2006. In addition, under the terms of the Indenture, NJNG could have issued approximately $424 million of additional first mortgage bonds as of September 30, 2006.

***Retail and Other* (All properties are located in New Jersey)**

At September 30, 2006, CR&R owned 122 acres of undeveloped land. See *Note 1. Impairment of Long-Lived Assets* in the accompanying Consolidated Financial Statements for a discussion of a change in strategy with regard to CR&R's 52 acres of Atlantic County land.

See *Item 1. Environment* for a discussion of regulatory matters concerning undeveloped land owned by CR&R.

NJRHS leases service centers in Town of Dover, Morris County, and Tinton Falls, Monmouth County.

Capital Expenditure Program

See *MD&A–Cash Flows* for a discussion of anticipated fiscal 2007 and 2008 capital expenditures for each business segment.

Item 3. LEGAL PROCEEDINGS

MGP Remediation

NJNG has identified 11 former MGP sites, dating back to the late 1800s and early 1900s, which contain contaminated residues from the former gas manufacturing operations. Ten of these 11 sites in question were acquired by NJNG in 1952. Gas manufacturing operations ceased at these sites at least by the mid-1950s and, in some cases, had been discontinued many years earlier. All of the former gas manufacturing facilities were subsequently dismantled by NJNG or the previous owners. Since October 1989, NJNG has been operating under Administrative Consent Orders or Memoranda of Agreement with the NJDEP covering all 11 sites. These orders and agreements establish the procedures to be followed in developing a final remedial cleanup plan for each site. NJNG is currently involved in administrative proceedings with the NJDEP with respect to the MGP sites in question and is participating in various studies and investigations by outside consultants to determine the nature and extent of any such contaminated residues and to develop appropriate programs of remedial action where warranted. Until September 2000, most of the cost of such studies and investigations had been shared under an agreement with the former owner and operator of 10 of the MGP sites, Jersey Central Power & Light (JCP&L), a subsidiary of FirstEnergy Corporation (FirstEnergy).

In September 2000, a revised agreement was executed pursuant to which NJNG is responsible for two of the sites, while JCP&L is responsible for the remaining eight sites. Also in September 2000, NJNG purchased a 20-year cost-containment insurance policy and an Environmental Response Compensation and Liability Insurance Policy (ERCLIP) for the two sites (see *Kemper Insurance Company Litigation* below.) On September 14, 2004, the BPU approved a simultaneous transfer of properties whereby NJNG would take ownership of two sites. NJNG continues to participate in the investigation and remedial action and bears the cost related to the one MGP site that was not subject to the original cost-sharing agreement.

In June 1992, the BPU approved a remediation rider through which NJNG may, subject to BPU approval, recover its remediation expenditures, including carrying costs, over rolling 7-year periods. On April 12, 2006, the BPU approved a stipulation that maintained the existing recovery rate of approximately $19.2 million annually. As of September 30, 2006, $83.7 million of previously incurred remediation costs, net of recoveries from customers as well as received and anticipated insurance proceeds, are included in Regulatory assets on the Consolidated Balance Sheet.

In March 1995, NJNG instituted an action for declaratory relief against 24 separate insurance companies in the Superior Court of New Jersey. These insurance carriers provided comprehensive general liability coverage to NJNG from 1951 through 1985. In July 1996, the complaint was amended to name Kaiser-Nelson Steel and Salvage Company (Kaiser-Nelson) and its successors for environmental damages caused by Kaiser-Nelson's decommissioning of structures at several MGP sites. In September 2001, NJNG reached a favorable settlement with the insurance carrier that provided the majority of NJNG's coverage. This settlement involved a significant cash payment to NJNG, which was credited to the remediation rider, and was received in four installments ending October 2004. In January 2006, NJNG reached a settlement of all claims with Kaiser-Nelson, which included a cash payment that was received by NJNG and credited to the remediation rider. Consequently, NJNG has now dismissed or reached a settlement with all of its insurance carriers who provided comprehensive general liability coverage to NJNG in connection with the MGP sites.

ITEM 3. LEGAL PROCEEDINGS (Continued)

NJNG is pursuing the potential settlement of alleged Natural Resource Damage (NRD) claims that might be brought by the NJDEP concerning three MGP sites. NJDEP has not made any specific demands for compensation for alleged injury to groundwater or other natural resources. NJNG's evaluation of these potential claims is in the early stages, and it is not yet possible to quantify the amount of compensation that NJDEP might seek to recover. NJNG anticipates any costs associated with this matter would be recoverable through the remediation rider.

Long Branch Litigation

Since July 2003, a series of complaints were filed in the New Jersey Superior Court against NJNG, NJR, JCP&L and FirstEnergy. The complaints were originally filed in Monmouth County and, as of February 2004, were designated as a Mass Tort Litigation (the "Mass Tort Litigation") for centralized case management purposes and transferred to the Bergen County Law Division. There were originally 528 complaints filed. All 528 complaints have been dismissed or settled, as described below.

Among other things, the complaints alleged personal injuries, wrongful death, survivorship actions, property damage and claims for medical monitoring stemming from the operation and remediation of the former MGP site in Long Branch, New Jersey. The relief sought included compensatory damages, the establishment of a medical monitoring fund, disgorgement of alleged profits, cost of cleanup and remediation, natural resource damages and punitive damages.

In December 2005, a confidential settlement between NJNG and the plaintiffs was finalized and approved by the New Jersey Superior Court in Bergen County.

JCP&L and FirstEnergy made a demand upon NJNG and NJR for indemnification pursuant to the September 2000 agreement between these entities and NJNG, whereby NJNG assumed responsibility for the Long Branch site. NJNG has agreed to honor the indemnification terms of the agreement. NJNG's insurance carriers were initially notified of the claims, and Kemper Insurance Company (Kemper), under the ERCLIP, initially agreed to provide a defense and certain coverage, subject to a reservation of rights regarding various allegations in the complaints, typically not covered by insurance against Kemper (see *Kemper Insurance Company Litigation* below).

Management believes that litigation costs and the settlement amount are recoverable through insurance (subject to the outcome of the Kemper Insurance Company Litigation). Additionally, management believes that any liabilities not recoverable through insurance, except for punitive and personal injury damages, would be recoverable, with BPU approval, through the remediation rider. However, there can be no assurance as to the ultimate resolution of the recovery of these amounts or the impact on the Company's financial condition, results of operations or cash flows.

Twelve *pro se* matters have been filed against the Company and NJNG since February 26, 2005. These complaints were filed in the Superior Court of New Jersey Law Division, Bergen County and allege the same claims made in the Mass Tort Litigation. There are five active cases remaining. The others have been dismissed or disposed of by the court. NJNG and the Company believe that the allegations in the complaints have no merit and are vigorously defending against them.

ITEM 3. LEGAL PROCEEDINGS (Continued)

The amount of total liability resulting from the *pro se* matters described in the preceding paragraph, if any, and any related insurance recovery cannot be determined at this time; however, based on information and relevant circumstances known at this time, management does not believe these suits will have a material adverse effect on the Company's financial condition, results of operations or cash flows.

Kemper Insurance Company Litigation

In October 2004, NJNG instituted suit for declaratory relief against Kemper in the Superior Court of New Jersey Law Division, Ocean County. The matter is under active case management. Kemper provided insurance under an ERCLIP together with a cost containment coverage policy effective July 21, 2000. Prior to the institution of this suit, NJNG requested that Kemper defend and indemnify claims involving the Mass Tort Litigation (see *Long Branch Site Litigation* , above) and reimburse NJNG for remediation costs for the Long Branch site that exceed the self-insured retention. Kemper reserved its rights regarding various allegations in the Mass Tort Litigation and agreed to participate in the defense of that matter. Although Kemper has not denied coverage, it has not yet reimbursed NJNG for any costs incurred to date. In fiscal 2003, Kemper ceased its underwriting operations and voluntarily commenced a runoff of its business. The Illinois Department of Insurance has approved Kemper's runoff plan. Management believes that, with the exception of any liability for punitive and personal injury damages, any costs associated with Kemper's failure to meet its future obligations will be recoverable, with BPU approval, through the remediation rider.

There can be no assurance as to the ultimate resolution of this matter or the impact on the Company's financial condition, results of operations or cash flows.

General

The Company is party to various other claims, legal actions and complaints arising in the ordinary course of business. In the Company's opinion, other than as disclosed in this Item 3. The ultimate disposition of these matters will not have a material adverse effect on its financial condition, results of operations or cash flows.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None

ITEM 4A. EXECUTIVE OFFICERS OF THE COMPANY

Office	Name	Age	Officer Since
Chairman, President and Chief Executive Officer	Laurence M. Downes	49	1986
Senior Vice President, Corporate Affairs	Kathleen T. Ellis	53	2004
Senior Vice President and Chief Financial Officer	Glenn C. Lockwood	45	1990
Senior Vice President, NJRES and NJNG	Joseph P. Shields	49	1996
Vice President and General Counsel	Mariellen Dugan	40	2005
Vice President, Marketing and Customer Services, NJNG	Kathleen F. Kerr	42	2005
Vice President, Energy Delivery, NJNG	Craig A. Lynch	45	2005
Vice President, Corporate Strategy, Service; Treasurer, NJNG	Thomas J. Massaro, Jr.	40	2004
Vice President, Internal Auditing	George C. Smith, Jr.	49	2004
Vice President, Regulatory Affairs, NJNG	Mark R. Sperduto	48	2005
Vice President, Corporate Services, Service	Deborah G. Zilai	53	1996
Corporate Secretary	Rhonda M. Figueroa	47	2005
Director of Government Affairs and Chief of Staff	Linda B. Kellner	47	2006

There is no arrangement or understanding between the officers listed above and any other person pursuant to which they were selected as officers. The following is a brief account of their business experience during the past five years:

Laurence M. Downes, Chairman, President and Chief Executive Officer

Mr. Downes has held the position of Chairman since September 1996. He has held the position of President and Chief Executive Officer s[illegible] July 1995. From January 1990 to July 1995, he held the position of Senior Vice President and Chief Financial Officer.

Kathleen T. Ellis, Senior Vice President, Corporate Affairs

Ms. Ellis has held the position of Senior Vice President, Corporate Affairs since December 2004. From December 2002 to November 2004, she held the position of Director of Communications for the Governor of the State of New Jersey, and from August 1998 to December 2002, she held the position of Manager of Communications and Director, State Governmental Affairs for Public Service Electric and Gas Company (PSE&G), a combined gas and electric utility company based in Newark, NJ .

Glenn C. Lockwood, Senior Vice President and Chief Financial Officer

Mr. Lockwood has held the position of Chief Financial Officer since September 1995 and the added position of Senior Vice President since January 1996. From January 1994 to September 1995, he held the position of Vice President, Controller and Chief Accounting Officer. From January 1990

ITEM 4A. EXECUTIVE OFFICERS OF THE COMPANY (Continued)

to January 1994, he held the position of Assistant Vice President, Controller and Chief Accounting Officer.

Joseph P. Shields, Senior Vice President, NJRES and NJNG

Mr. Shields joined NJNG in 1983 and has been Senior Vice President, NJRES since January 1996. As head of the energy services business unit, he is responsible for natural gas supply acquisitions, negotiating transportation agreements and monitoring natural gas control activities as well as regulated wholesale marketing activity for NJNG.

Mariellen Dugan, Vice President and General Counsel

Ms. Dugan has held the position of Vice President and General Counsel since December 2005. Prior to joining NJR, from February 2004 to November 2005, she held the position of First Assistant Attorney General for the State of New Jersey, and from February 2003 to February 2004, she held the position of Chief of Staff, Executive Assistant Attorney General of the State of New Jersey. From July 1999 to January 2003, Ms. Dugan was Of Counsel to the law firm of Kevin H. Marino P.C. in Newark, NJ.

Kathleen F. Kerr, Vice President, Marketing and Customer Services, NJNG

Mrs. Kerr joined NJNG as Vice President, Marketing and Customer Services in January 2005. Before joining NJNG, Mrs. Kerr was Director of Customer Service for PSE&G from April 2002 to December 2004. Prior thereto, she held various senior management level positions at PSE&G in customer services and other areas from April 1985 to December 2004.

Craig A. Lynch, Vice President, Energy Delivery, NJNG

Mr. Lynch has held the position of Vice President, Energy Delivery, NJNG, since November 2005. He joined NJNG in 1984 and is responsible for all aspects of NJNG's distribution, transmission, and utility operations. Prior to his current position, Mr. Lynch held the position of Director, Distribution, NJNG from July 1997 to October 2005. His duties were focused on the operation of the distribution system, ensuring that the expansion and maintenance of the system satisfied all federal, state, county and municipal regulations and conformed to all of NJNG's procedures and practices in an efficient and economical manner.

Thomas J. Massaro, Jr., Vice President, Corporate Strategy, Service; Treasurer, NJNG

Mr. Massaro has held the position of Vice President, Corporate Strategy, since June 2005 and the position of Treasurer at NJNG, since September 2006. He is responsible for the company's treasury function, strategic planning process and quality. He joined NJNG in June 1989 as a Management Engineer and has held several senior management positions in marketing, operations and customer service, including President of NJRHS from November 2004 to June 2005, and Director of Operations at NJRHS from January 2004 to November 2004.

ITEM 4A. EXECUTIVE OFFICERS OF THE COMPANY (Continued)

George C. Smith, Vice President, Internal Auditing

Mr. Smith joined NJR in 1984 as an Associate Auditor. He has held the position of Vice President, Internal Auditing since January 2004. In his prior role as Director of Internal Audit from 1998 to 2004, he redefined the internal audit function at NJR, implementing a new approach to identify and analyze controls and related processes.

Mark R. Sperduto, Vice President, Regulatory Affairs, NJNG

Mr. Sperduto joined NJNG in March 2005 and is responsible for the regulatory affairs strategy and supports initiatives on key issues such as price stability and improved service. Previously, Mr. Sperduto held the positions of Issues Manager-Financial and Director—Corporate Issues at PSE&G from November 2001 to March 2005 and held various positions there from August 1991 to November 2001. Mr. Sperduto started his career on the staff of the New Jersey Board of Public Utilities, holding various positions with the agency from 1980 to 1991.

Deborah G. Zilai, Vice President, Corporate Services, Service

Mrs. Zilai has held the position of Vice President, Corporate Services since June 2005. She joined New Jersey Resources in June 1996 after a twenty-year career at International Business Machines Corporation, where she held various management positions. Her current responsibilities include technology, human resources and supply chain management. From June 1996 to May 2005, she served as Vice President, Information Systems and Services.

Rhonda M. Figueroa, Corporate Secretary

Ms. Figueroa has held the position of Corporate Secretary since March 2006. Her responsibilities include serving as the secretary to the Board of Directors of NJR and its subsidiaries as well as various internal committees. She also serves as the company's registered agent and ' 'r of records. Ms. Figueroa joined NJR in 1981. From November 2005 to March 2006 she held the position of Assistant Corporate ' ary, from August 2002 to November 2005, she held the position of Manager of Business Transformation, and from August 2001 to August 2002, she held the position of Manager of Marketing Services for NJRHS.

Linda B. Kellner, Director of Government Affairs and Chief of Staff

Ms. Kellner has held the position of Chief of Staff since February 2001 and the position of Director of Government Affairs since January 2003. She currently is responsible for state and federal legislative activities impacting the energy industry, community relations as they relate to the Company's environmental remediation projects, the corporate-wide Diversity initiative and preparation of communications for the NJR Board of Directors. From January of 2000 to January of 2003, she held the position of Manager of Government Affairs and from October of 1995 to December of 1999, she served as Manager of Policy Analysis.

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NJR's Common Stock is traded on the New York Stock Exchange under the ticker symbol NJR. As of September 30, 2006 , NJR had 16,679 holders of record of its common stock.

NJR's common stock high and low sales prices and dividends paid per share were as follows:

	2006		2005		Dividends Paid	
	High	**Low**	High	Low	**2006**	2005
Fiscal Quarter						
First	**$ 46.95**	**$ 40.68**	$ 44.55	$ 40.54	**$ .34**	$ .325
Second	**$ 45.96**	**$ 41.49**	$ 45.50	$ 41.20	**$ .36**	$ .340
Third	**$ 47.38**	**$ 42.85**	$ 48.42	$ 42.63	**$ .36**	$ .340
Fourth	**$ 51.39**	**$ 46.34**	$ 49.34	$ 44.43	**$ .36**	$ .340

The Company has been authorized by its Board of Directors to cumulatively repurchase up to 3.5 million shares of its common stock through a repurchase program that was initiated in 1996. As of September 30, 2006, the Company has repurchased approximately 3.15 million shares of its common stock.

The following table sets forth NJR's repurchase activity for the quarter ended September 30, 2006:

Period	Total Number of Shares (or Units) Purchased (a)	Average Price Paid per Share (or Unit) (b)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (c)	Maximum Number (or Approximate Dollar Value) of Shares (or Units) That May Yet Be Purchased Under the Plans or Programs (d)
7/1/06 – 7/31/06	-	-	-	1,038,147
8/1/06 – 8/31/06	118,200	49.36	118,200	919,947
9/1/06 – 9/30/06	571,800	49.59	571,800	348,147
Total	**690,000**	**49.55**	**690,000**	**348,147**

The chief executive officer's annual certification regarding the Company's compliance with the NYSE's corporate governance listing standards was submitted to the NYSE in February 2006.

Item 6. SELECTED FINANCIAL DATA

CONSOLIDATED FINANCIAL STATISTICS

(Thousands, except per share data)

Fiscal Years Ended September 30,	2006	2005	2004	2003	2002	2001
SELECTED FINANCIAL DATA						
Operating Revenues	$ 3,299,608	$ 3,148,262	$ 2,533,607	$ 2,542,865	$ 1,830,033	$ 2,047,080
Operating Expenses						
Gas purchases	2,909,789	2,780,343	2,213,374	2,238,394	1,566,467	1,782,840
Operation and maintenance	121,384	108,071	101,118	101,438	87,499	84,445
Regulatory rider expenses	28,587	31,594	9,540	4,592	4,147	4,903
Depreciation and amortization	34,753	33,675	32,449	31,965	31,844	32,530
Energy and other taxes	58,632	56,211	49,908	46,639	36,792	43,770
Total Operating Expenses	3,153,145	3,009,894	2,406,389	2,423,028	1,726,749	1,948,488
Operating Income	146,463	138,368	127,218	119,837	103,284	98,592
Other income	7,747	7,359	5,696	2,029	6,040	7,667
Interest charges, net	25,669	20,474	15,395	13,992	16,556	19,705
Income before Income Taxes	128,541	125,253	117,519	107,874	92,768	86,554
Income tax provision	50,022	48,913	45,945	42,462	35,924	32,891
Income before Accounting Change	78,519	76,340	71,574	65,412	56,844	53,663
Cumulative effect of a change in accounting, net of taxes	—	—	—	—	—	(1,347)
Net Income	$ 78,519	$ 76,340	$ 71,574	$ 65,412	$ 56,844	$ 52,316
CAPITALIZATION						
Common stock equity	$ 621,662	$ 438,052	$ 467,917	$ 418,941	$ 361,453	$ 352,069
Redeemable preferred stock	—	—	—	—	295	298
Long-term debt	332,332	317,204	315,887	257,899	370,628	353,799
Total Capitalization	$ 953,994	$ 755,256	$ 783,804	$ 676,840	$ 732,376	$ 706,166
PROPERTY, PLANT AND EQUIPMENT						
Utility plant	$ 1,243,586	$ 1,197,418	$ 1,148,865	$ 1,097,591	$ 1,053,086	$ 1,016,911
Accumulated depreciation	(326,298)	(307,100)	(287,146)	(270,673)	(248,980)	(230,373)
Real estate properties and other	27,136	24,340	24,439	30,999	25,144	26,759
Accumulated depreciation	(9,485)	(9,528)	(5,769)	(5,313)	(5,075)	(4,647)
Property, Plant and Equipment, Net	$ 934,939	$ 905,130	$ 880,389	$ 852,604	$ 824,175	$ 808,650
CAPITAL EXPENDITURES						
Utility plant	$ 53,060	$ 52,801	$ 60,313	$ 46,653	$ 42,314	$ 44,176
Real estate properties and other	5,734	1,597	13,304	6,614	924	5,872
Investments available for sale	—	—	—	—	—	1,669
Cost of removal	7,499	6,502	5,042	4,308	4,715	5,629
Total Capital Expenditures	$ 66,293	$ 60,900	$ 78,659	$ 57,575	$ 47,953	$ 57,346
Total Assets *(a)*	$ 2,398,928	$ 2,330,248	$ 1,861,979	$ 1,584,775	$ 1,455,589	$ 1,328,844

(a) Total assets for 2005, 2004 and 2001 have been reclassified to reflect broker margin deposit amounts.

ITEM 6. SELECTED FINANCIAL DATA (Continued)

(Thousands, except per share data)

Fiscal Years Ended September 30,	**2006**	2005	2004	2003	2002	2001
COMMON STOCK DATA						
Earnings per share–Basic	**$ 2.82**	$ 2.77	$ 2.60	$ 2.41	$ 2.12	$ 1.97
Earnings per share–Diluted	**$ 2.80**	$ 2.71	$ 2.55	$ 2.38	$ 2.09	$ 1.95
Dividends declared per share	**$ 1.44**	$ 1.36	$ 1.30	$ 1.24	$ 1.20	$ 1.17
Payout ratio	**51 %**	49 %	50 %	51 %	57 %	59 %
Market price at year-end	**$ 49.30**	$ 45.98	$ 41.40	$ 36.04	$ 32.90	$ 29.47
Dividend yield at year-end	**2.9 %**	3.0 %	3.1 %	3.4 %	3.6 %	4.0 %
Price-earnings ratio	**17**	17	16	15	16	15
Book value per share	**$ 22.50**	$ 15.90	$ 16.87	$ 15.38	$ 13.43	$ 13.20
Market-to-book ratio at year-end	**2.2**	2.9	2.5	2.3	2.5	2.2
Shares outstanding at year-end	**27,625**	27,546	27,741	27,233	26,917	26,664
Average shares outstanding–Basic	**27,862**	27,591	27,530	27,095	26,860	26,598
Average shares outstanding–Diluted	**28,081**	28,121	28,053	27,532	27,168	26,801
Return on average equity *(a)*	**14.4 %**	15.3 %	15.6 %	15.9 %	15.3 %	15.3 %

(a) Excluding accumulated other comprehensive income.

ITEM 6. SELECTED FINANCIAL DATA (Continued)

NJNG OPERATING STATISTICS

Fiscal Years Ended September 30,	2006	2005	2004	2003	2002	2001
Operating Revenues (Thousands)						
Residential	$ 598,274	$ 568,324	$ 496,866	$ 433,634	$ 359,022	$ 404,539
Commercial and other	172,465	143,211	118,326	99,587	84,449	99,518
Firm transportation	28,656	29,566	28,987	34,682	24,455	31,292
Total residential and commercial	799,395	741,101	644,179	567,903	467,926	535,349
Interruptible	12,134	14,377	9,575	8,406	12,608	11,788
Total system	811,529	755,478	653,754	576,309	480,534	547,137
Incentive programs	327,245	382,802	275,148	183,569	294,007	462,340
Total Operating Revenues	$ 1,138,774	$ 1,138,280	$ 928,902	$ 759,878	$ 774,541	$ 1,009,477
Throughput (Bcf)						
Residential	39.4	43.7	44.1	46.2	35.3	41.0
Commercial and other	10.4	11.3	10.9	10.9	8.7	10.5
Firm transportation	7.4	7.6	8.4	10.4	7.0	9.3
Total residential and commercial	57.2	62.6	63.4	67.5	51.0	60.8
Interruptible	7.2	9.7	8.9	7.4	11.1	11.7
Total system	64.4	72.3	72.3	74.9	62.1	72.5
Incentive programs	38.4	52.4	47.1	35.8	96.5	88.4
Total Throughput	102.8	124.7	119.4	110.7	158.6	160.9
Customers at Year-End						
Residential	429,834	418,646	410,005	397,584	390,681	378,803
Commercial and other	28,914	28,878	27,718	26,313	25,564	25,417
Firm transportation	12,874	15,246	16,387	19,867	17,811	18,879
Total residential and commercial	471,622	462,770	454,110	443,764	434,056	423,099
Interruptible	48	47	63	51	51	53
Incentive programs	35	39	35	25	34	30
Total Customers at Year-End	471,705	462,856	454,208	443,840	434,141	423,182
Interest Coverage Ratio	7.63	6.38	7.38	7.65	6.18	5.23
Average Therm Use per Customer						
Residential	920	1,045	1,079	1,178	895	1,109
Commercial and other	5,084	5,443	5,646	6,182	4,962	5,961
Degree Days	4,367	4,927	4,810	5,354	3,964	5,070
Weather as a Percent of Normal	90 %	102 %	99 %	111 %	83 %	105 %
Number of Employees	516	518	539	551	547	542

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

Management's Overview

New Jersey Resources Corporation (NJR or the Company) is an energy services holding company providing retail natural gas service in New Jersey and wholesale natural gas and related energy services to customers in states from the Gulf Coast and Mid-Continent to New England and Canada through its two principal subsidiaries, New Jersey Natural Gas (NJNG) and NJR Energy Services (NJRES).

NJNG is a natural gas utility which provides regulated retail natural gas service in central and northern New Jersey and also participates in the off-system sales and capacity release markets, and comprises the Natural Gas Distribution segment. NJNG is regulated by the New Jersey Board of Public Utilities (BPU).

NJRES maintains and trades around a portfolio of physical assets consisting of natural gas storage and transportation contracts. As well, NJRES provides wholesale energy services to non-affiliated utility and energy companies. NJRES comprises the Energy Services segment.

The Retail and Other segment includes NJR Home Services (NJRHS), which provides service, sales and installation of appliances; NJR Energy, an investor in energy-related ventures, most significantly, through NJNR Pipeline it holds the Company's 5.53 percent interest in Iroquois Gas and Transmission System, LP (Iroquois), which is a 412-mile natural gas pipeline from the New York-Canadian border to Long Island, New York; Commercial Realty and Resources (CR&R), which holds and develops commercial real estate; and NJR Investment, which makes energy-related equity investments.

Net income and assets by business segment are as follows:

($ in thousands)	**2006**		2005		2004	
Net Income						
Natural Gas Distribution	**$46,870**	**60%**	$53,376	70%	$55,524	78%
Energy Services	**28,113**	**36**	16,483	22	13,572	19
Retail and Other	**3,536**	**4**	6,481	8	2,478	3
Total	**$78,519**	**100%**	$76,340	100%	$71,574	100%

($ in thousands)	**2006**		2005		2004	
Assets						
Natural Gas Distribution	**$ 1,586,934**	**66%**	$ 1,581,758	68%	$ 1,359,603	73%
Energy Services	**714,867**	**30**	621,471	27	397,741	21
Retail and Other	**97,127**	**4**	127,019	5	104,635	6
Total	**$ 2,398,928**	**100%**	$ 2,330,248	100%	$ 1,861,979	100%

Natural Gas Distribution Segment

Natural Gas Distribution operations have been managed with the goal of growing profitably without the need for traditional base rate increases. NJNG, working together with the BPU and the

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

New Jersey Department of the Public Advocate, Division of Rate Counsel (formerly called the Division of the Ratepayer Advocate), has been able to accomplish this goal for more than 12 years through several key initiatives including:

- Managing its customer growth, which is expected to total about 2.2 percent annually;
- Generating earnings from various BPU-authorized gross margin-sharing incentive programs, which are currently approved through October 31, 2007;
- Reducing the impact of weather on NJNG's earnings through a Weather-Normalization Clause (WNC);
- Managing the volatility of wholesale natural gas prices through a hedging program to help keep customers' prices as stable as possible; and
- Improving its cost structure through various productivity initiatives.

In conducting NJNG's business, management focuses on factors it believes may have significant influence on its future financial results. NJNG's policy is to work with all stakeholders, including customers, regulators and policymakers, to achieve favorable results. These factors include the rate of NJNG's customer growth in its service territory, which can be influenced by general economic conditions as well as political and regulatory policies that may impact the new housing market. A portion of NJNG's customer growth comes from the conversion market, which is influenced by the delivered cost of natural gas compared with competing fuels, interest rates and other economic conditions.

For the reporting periods through September 30, 2006, the impact of weather on NJNG's utility gross margin had been significantly mitigated due to its WNC, however, lower customer usage per degree-day was not captured by the WNC. NJNG has experienced lower customer usage per degree-day, which it believes is due primarily to customer conservation resulting from an increase in wholesale natural gas commodity costs. In order to reduce the impact of the reduction in customer usage, NJNG filed a Conservation and Usage Adjustment (CUA) proposal with the BPU in December 2005. On October 12, 2006, the BPU approved a stipulation that was reached with the staff of the BPU and the Division of Rate Counsel on September 30, 2006, which modified the CUA proposal into the Conservation Incentive Program (CIP).

The CIP is a three-year pilot program, designed to decouple the link between customer usage and NJNG's utility gross margin to allow NJNG to encourage its customers to conserve energy. For the term of the pilot the existing WNC would be suspended and replaced with the CIP tracking mechanism, which addresses utility gross margin variations related to both weather and customer usage in comparison to established benchmarks. Recovery of such utility gross margin variations is subject to additional conditions including an earnings test and an evaluation of Basic Gas Supply Service (BGSS)-related savings achieved. Under the CIP agreement, if NJNG does not file for a rate review with the BPU within two years, the return on equity for the earnings test will decline from 10.5 percent to 10.25 percent. To encourage energy efficiency, NJNG is also required to initiate programs to further customer conservation efforts over the term of the pilot. NJNG shall provide an initial

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

$2 million in funding for such programs and will continue to fund programs throughout the term of the pilot. At September 30, 2006, the obligation to fund these conservation programs was recorded at its present value of $1.8 million and recognized as a component of Operating and maintenance expense in the Consolidated Statements of Income. An annual filing for the clause must be made in June of each year, coincident with NJNG's annual BGSS filing.

NJNG's operating expenses are heavily influenced by labor costs, large components of which are covered by a negotiated collective bargaining agreement that expires in 2008. Labor-related fringe benefit costs, which are also subject to numerous factors, may also influence NJNG's results.

As a regulated company, NJNG is required to recognize the impact of regulatory decisions on its financial statements. As a result, significant costs are deferred and treated as regulatory assets, pending BPU decisions regarding their ultimate recovery from customers. The most significant costs incurred that are subject to this accounting treatment include manufactured gas plant (MGP) remediation costs and wholesale natural gas costs. Actual remediation costs may vary from management's estimates due to the developing nature of remediation requirements and related litigation. If there are changes in the regulatory position on the recovery of these costs, such costs would be charged to income.

Due to the capital-intensive nature of NJNG's operations and the seasonal nature of its working capital requirements, significant changes in interest rates can also impact NJNG's results.

Energy Services Segment

The Energy Services segment is focused on maximizing physical asset values that it controls through the use of contractual rights, which allows NJRES to take advantage of differences in pricing across geographic regions and/or time periods. NJRES also seeks to utilize its r tplace knowledge in capacity and supply contract management for other utilities and energy companies.

The Energy Services segment focuses on providing wholesale energy services, including base load natural gas services, peaking services and balancing services, utilizing physical assets it controls, as well as natural gas management services to third parties. NJRES' contribution to earnings has increased over the past several years due primarily to increases in its portfolio of pipeline and storage capacity and the volatile nature of wholesale natural gas prices. The volatile nature of wholesale natural gas prices over short periods of time can significantly impact NJRES' revenue and gross margin. Furthermore, gross margin for NJRES is generally greater during the winter months, while the fixed costs of its capacity assets are generally spread throughout the year. Future growth is expected to come from opportunities that include the acquisition of additional storage and pipeline capacity assets and portfolio management services for third parties.

Retail and Other Segment

In the Retail and Other segment, NJRHS is focused on growing its installation business and expanding its service contract customer base. CR&R seeks additional opportunities to enhance the value of its undeveloped land.

1 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued)

Critical Accounting Policies

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States of America (GAAP). Application of these accounting principles requires the use of estimates and assumptions that affect the reported amounts of liabilities, revenues and expenses, and related disclosures of contingencies during the reporting period. The Company regularly evaluates its estimates, including those related to the calculation of the fair value of natural gas commodity contracts and derivative instruments, unbilled revenues, provisions for depreciation and amortization, regulatory assets, income taxes, pension and postemployment benefits other than pensions and contingencies related to environmental matters and litigation. NJR bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. In the normal course of business, estimated amounts are subsequently adjusted to actual results that may differ from estimates.

Regulatory Accounting

NJNG maintains its accounts in accordance with the Uniform System of Accounts as prescribed by the BPU. As a result of the ratemaking process, NJNG is required to follow Statement of Financial Accounting Standards (SFAS) No. 71, *"Accounting for the Effects of Certain Types of Regulation"* (SFAS 71), and consequently, the accounting principles applied by NJNG differ in certain respects from those applied by unregulated businesses. NJNG is required under SFAS 71 to recognize the impact of regulatory decisions on its financial statements. NJNG's BGSS requires NJNG to project its natural gas costs and provides the ability, subject to BPU approval, to recover or refund the difference, if any, of such actual costs as compared with the projected costs included in prices through a BGSS charge to customers. Any underrecovery or overrecovery is recorded as a Regulatory asset or liability on the Consolidated Balance Sheets and reflected in the BGSS charge to customers in subsequent years. NJNG also enters into derivatives that are used to hedge natural gas purchases, and the offset to the resulting fair value of ' tive assets or liabilities is recorded as a Regulatory asset or liability on the Consolidated Balance Sheets.

In addition to the BGSS, other regulatory assets consist primarily of remediation costs associated with MGP sites, the WNC, the New Jersey Clean Energy Program and the Universal Service Fund Program, all of which are subject to BPU approval. If there are changes in future regulatory positions that indicate the recovery of such regulatory assets is not probable, the related cost and carrying costs would be charged to income in the period of such determination.

Derivatives

Derivative activities are recorded in accordance with SFAS No. 133, " *Accounting for Derivative Instruments and Hedging Activities,"* as amended (SFAS 133), under which NJR records the fair value of derivatives held as assets and liabilities. NJR's unregulated subsidiaries record changes in the fair value of the effective portion of derivatives qualifying as cash flow hedges, net of tax, in Accumulated other comprehensive income, a component of Common stock equity. Under SFAS 133, NJR also has

certain derivative instruments that do not qualify as hedges. The change in fair value of these derivatives is recorded in Gas purchases on the Consolidated Statements of Income. In addition, the changes in the fair value of the ineffective portion of derivatives qualifying for hedge accounting are recorded as increases or decreases in natural gas costs or interest expense, as applicable, based on the nature of the derivatives.

NJNG's derivatives that are used to hedge its natural gas purchasing activities are recoverable through its BGSS, subject to BPU approval. Accordingly, the offset to the change in fair value of these derivatives is recorded as a Regulatory asset or liability on the Consolidated Balance Sheets.

NJR has not designated any derivatives as fair value hedges as of September 30, 2006 and 2005.

In providing its unregulated wholesale energy services, NJRES enters into physical contracts to buy and sell natural gas. These contracts qualify for the "normal purchase normal sale" scope exception under SFAS 133 in that they provide for the purchase or sale of natural gas that will be delivered in quantities expected to be used or sold by NJRES over a reasonable period of time in the normal course of business. Accordingly, NJRES accounts for these contracts under accrual accounting.

The fair value of derivative investments is determined by reference to quoted market prices of listed contracts, published quotations or quotations from independent parties. NJRES' trading portfolio is valued using a combination of proprietary modeling methods and the most currently available market pricing and data. Should there be a significant change in model assumptions, or in the underlying market prices or data, or should certain contracts fail to meet the normal purchase normal sale scope exception of SFAS 133, NJRES may experience a significant impact on its financial position, results of operations and cash flows.

Environmental Costs

At the end of each fiscal year, NJNG updates the environmental review of its MGP sites, including a review of its potential liability for litigation and remedial action, based on assistance from an outside consulting firm. From this review, NJNG estimates expenditures to remediate and monitor these MGP sites, exclusive of any insurance recoveries. NJNG's estimate of these liabilities is developed from then currently available facts, existing technology and presently enacted laws and regulations.

Where the information is sufficient to establish only a range of probable liability, and no point within the range is more likely than any other, it is NJNG's policy to accrue the lower end of the range. Since management believes that recovery of these expenditures, as well as related litigation costs, is probable through the regulatory process, in accordance with SFAS 71, it has recorded a regulatory asset corresponding to the accrued liability.

The actual costs to be incurred by NJNG are dependent upon several factors, including final determination of remedial action, changing technologies and governmental regulations, the ultimate ability of other responsible parties to pay, the impact of litigation and any insurance recoveries. If there are changes in future regulatory positions that indicate the recovery of all or a portion of such

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

regulatory asset is not probable, the related cost and carrying costs would be charged to income in the period of such determination. As of September 30, 2006 and 2005, $83.7 million and $86.9 million of previously incurred remediation costs, net of recoveries from customers and insurance proceeds received and anticipated, is included in Regulatory assets on the Consolidated Balance Sheet, respectively.

If there are changes in the regulatory position surrounding these costs, or should actual expenditures vary significantly from estimates in that these costs are disallowed for recovery by the BPU, such costs would be charged to income in the period of such determination.

Postemployment Employee Benefits

NJR's costs of providing postemployment employee benefits are dependent upon numerous factors including actual plan experience and assumptions of future experience. Postemployment employee benefit costs, for example, are impacted by actual employee demographics including age, compensation levels and employment periods, the level of contributions made to the plans and the return on plan assets. Changes made to the provisions of the plans may also impact current and future postemployment employee benefit costs. Postemployment employee benefit costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, health care cost trends and discount rates used in determining the projected benefit obligations (PBO). In determining the PBO and cost amounts, assumptions can change from period to period and could result in material changes to net postemployment employee benefit periodic costs and the related liability recognized by NJR.

NJR's postemployment employee benefit plan assets consist primarily of U.S. equity securities, international equity securities and fixed-income investments, with a targeted allocation of 53 percent, 18 percent and 29 percent, respectively. Fluctuations in actual market returns, as well as changes in interest rates, may result in increased or decreased postemployment employee benefit costs in future periods. Postemployment employee benefit expenses are included in Operations and maintenance expense on the Consolidated Statements of Income.

The following is a summary of a sensitivity analysis for each actuarial assumption:

Pension Plans

Actuarial Assumptions	Increase/ (Decrease)	Estimated Increase/ (Decrease) on PBO (Thousands)	Estimated Increase/ (Decrease) to Expense (Thousands)
Discount rate	1.00%	$ (14,420)	$ (1,395)
Discount rate	(1.00)%	$ 16,657	$ 1,503
Rate of return on plan assets	1.00 %	n/a	$ (792)
Rate of return on plan assets	(1.00)%	n/a	$ 792

1. *1* 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued)

Other Postemployment Benefits

Actuarial Assumptions	Increase/ (Decrease)	Estimated Increase/ (Decrease) on PBO (Thousands)	Estimated Increase/ (Decrease) to Expense (Thousands)
Discount rate	1.00%	$ (7,249)	$ (649)
Discount rate	(1.00)%	$ 9,227	$ 803
Rate of return on plan assets	1.00 %	n/a	$ (216)
Rate of return on plan assets	(1.00)%	n/a	$ 214

Actuarial Assumptions	Increase/ (Decrease)	Estimated Increase/ (Decrease) on PBO (Thousands)	Estimated Increase/ (Decrease) to Expense (Thousands)
Heath care cost trend rate	1.00%	$ 8,096	$ 921
Health care cost trend rate	(1.00)%	$ (6,489)	$ (721)

New Accounting Standards

In July 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, *"Accounting for Uncertainty in Income Taxes"* (FIN 48), which alters the framework for recognizing income tax contingencies. Previously, under SFAS No. 5, *"Accounting for Contingencies,"* the focus was on the subsequent liability recognition for estimated losses from tax contingencies where such losses were probable and the related amounts could be reasonably estimated. Under this new interpretation, a contingent tax asset (i.e., an uncertain tax position) may only be recognized if it is more likely than not that it will ultimately be sustained upon audit. The Company will adopt FIN 48 by the commencement of fiscal 2008. The Company is evaluating its tax positions for all jurisdictions and all years for which the statute of limitations remains open, as well as evaluating the impact that the adoption will have on its financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 defines fair value as the amount that would be exchanged to sell an asset or transfer a liability, in an orderly transaction between market participants, and establishes a fair value hierarchy of quotes and unobservable data that should be used to develop pricing assumptions. In addition, for assets and liabilities that are not actively traded, for example, certain kinds of derivatives, SFAS 157 requires that a fair value measurement include an adjustment for risks inherent in a valuation technique and/or inputs, such as those used in pricing models. SFAS 157 is effective for fiscal years beginning after November 15, 2007, however, early adoption is permitted. The Company will adopt the provisions of the statement prospectively and is evaluating the adoption date and its effect on its financial condition.

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

In September 2006, the FASB issued SFAS No. 158, *"Employers' Accounting for Defined Benefit Pension and Other Postemployment Plans"* (SFAS 158). The statement requires an employer to recognize the funded status, measured as the difference between the fair value of plan assets and the projected benefit obligation, of its benefit plans. SFAS 158 does not change how pensions and other postemployment benefits are accounted for and reported in the income statement. Certain economic events, which previously required disclosure only in the notes to the financial statements, will be recognized as assets and liabilities and offset in Accumulated other comprehensive income, net of tax, on the Statement of Common Stock Equity to the extent such amounts are not recognized in earnings as part of net periodic benefit costs. Amounts recognized in Accumulated other comprehensive income are adjusted as they are subsequently recognized in earnings. The Company will adopt SFAS 158 on September 30, 2007 and will apply the provisions of the statement prospectively. The Company is currently evaluating the effect of adoption on its financial condition.

Results of Operations

Consolidated

Net income increased 2.8 percent to $78.5 million in fiscal 2006, 6.6 percent to $76.3 million in fiscal 2005 and 9.4 percent to $71.6 million in fiscal 2004. The fiscal 2006 results were $2.82 per basic share and $2.80 per diluted share, compared with the fiscal 2005 results of $2.77 per basic share and $2.71 per diluted share. Fiscal 2005 results included a gain of $.22 per basic share ($.21 per diluted share) on the sale of a commercial office building, a charge of $.05 per basic and diluted share associated with an early retirement program for officers and a charge of $.09 per basic and diluted share due to a change in strategy at CR&R. Net of these items, NJR's earnings in fiscal 2005 were $74.4 million, or $2.70 per basic share and $2.65 per diluted share.

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

Following is a reconciliation of as reported and as adjusted information for Net income and basic and diluted earnings per share for fiscal 2005. This reconciliation reflects the impact of the gain on sale of the commercial office building, the charge related to an early retirement program for officers and the charge for the impairment of certain undeveloped land. Management believes that this reconciliation is needed due to the unusual nature of these items and that they are not indicative of core results. It also provides a more consistent comparison for year-over-year results:

(Unaudited)
(Thousands, except per share data)

	For Twelve Months Ended September 30, 2005			
	NJNG	NJRES	NJRHS and Other	Total
Net Income, as reported	$ 53,376	$ 16,483	$ 6,481	$ 76,340
Exclude:				
Gain on sale of commercial office building, net of tax			(5,972)	(5,972)
Charge for early retirement program, net of tax	1,195	56	241	1,492
Charge for impairment of undeveloped land, net of tax			2,532	2,532
Net Income, as adjusted	$ 54,571	$ 16,539	$ 3,282	$ 74,392
Earnings per share basic, as reported				$ 2.77
Exclude:				
Gain on sale of commercial office building, net of tax				(.22)
Charge for early retirement program, net of tax				.05
Charge for impairment of undeveloped land, net of tax				.09
Earnings per share basic, as adjusted*				$ 2.70
Earnings per share diluted, as reported				$ 2.71
Exclude:				
Gain on sale of commercial office building, net of tax				(.21)
Charge for early retirement program, net of tax				.05
Charge for impairment of undeveloped land, net of tax				.09
Earnings per share diluted, as adjusted *				$ 2.65

** Amount does not sum due to rounding of individual components*

Natural Gas Distribution Operations

NJNG is a local natural gas distribution company that provides regulated retail energy services to approximately 471,000 residential and commercial customers in central and northern New Jersey and participates in the off-system sales and capacity release markets.

NJNG's business is seasonal by nature, as weather conditions directly influence the volume of natural gas delivered. Specifically, customer demand substantially increases during the winter months when natural gas is used for heating purposes. As a result, NJNG receives most of its gas distribution revenues during the first and second fiscal quarters and is subject to variations in earnings and working capital during the year.

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

In February 1999, the Electric Discount and Energy Competition Act (EDECA), which provides the framework for the restructuring of New Jersey's energy markets, became law. In March 2001, the BPU issued an order to fully open NJNG's residential markets to competition, restructure its rates to segregate its BGSS and delivery (i.e., transportation) service prices as required by EDECA and expand an incentive for residential and small commercial customers to switch to transportation service. NJNG earns no utility gross margin on the commodity portion of its natural gas sales. NJNG earns utility gross margin through the delivery of natural gas to its customers. In January 2002, the BPU ordered that BGSS could be provided by suppliers other than the state's natural gas utilities, but BGSS should be provided by the state's natural gas utilities until further BPU action. No additional action has been taken by the BPU subsequent to its initial order in January 2002.

NJNG's financial results are summarized as follows:

(Thousands)	2006	2005	2004
Utility Gross Margin			
Operating revenues	$ 1,138,774	$ 1,138 ,280	$ 928,902
Less:			
Gas purchases	847,276	846,373	663,436
Energy and other taxes	52,908	50,517	45,150
Regulatory rider expense	28,587	31,594	9,540
Total Utility Gross Margin	$ 210,003	$ 209,796	$ 210,776
Utility Gross Margin			
Residential and commercial	$ 178,732	$ 179,374	$ 178,871
Transportation	22,850	23,209	24,928
Total Utility Firm Gross Margin	201,582	202,583	203,799
Incentive programs	7,403	6,092	5,832
Interruptible	1,018	1,121	1,145
Total Utility Gross Margin	210,003	209,796	210,776
Operation and maintenance expense	84,907	76,532	77,442
Depreciation and amortization	34,146	32,905	31,776
Other taxes not reflected in utility gross margin	2,921	2,857	2,735
Operating income	$ 88,029	$ 97,502	$ 98,823
Other income	$ 3,448	$ 3,050	$ 4,434
Interest charges, net	$ 16,456	$ 14,293	$ 12,775
Net income	$ 46,870	$ 53,376	$ 55,524

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

The following table summarizes total throughput in billion cubic feet (Bcf) of natural gas by type through the NJNG distribution system:

(Bcf)	**2006**	2005	2004
Throughput			
Residential and commercial	**49.8**	55.0	55.0
Transportation	**7.4**	7.6	8.4
Total Firm Throughput	**57.2**	62.6	63.4
Incentive programs	**38.4**	52.4	47.1
Interruptible	**7.2**	9.7	8.9
Total Throughput	**102.8**	124.7	119.4

Utility Gross Margin

NJNG's utility gross margin is defined as natural gas revenues less natural gas purchases, sales tax, a Transitional Energy Facilities Assessment (TEFA) and regulatory rider expenses. Management believes that utility gross margin provides a more meaningful basis than revenue for evaluating utility operations since natural gas costs, sales tax, TEFA and regulatory rider expenses are included in operating revenue and passed through to customers and, therefore, have no effect on utility gross margin. This definition of utility gross margin may not be comparable to the definition of gross margin used by others in the natural gas distribution business and other industries.

Natural gas costs are charged to operating expenses on the basis of therm sales at the prices in NJNG's BGSS tariff, approved by the BPU. The BGSS tariff includes projected natural gas costs, net of supplier refunds, the impact of hedging activities and credits from non-firm sales and transportation activities. Any underrecoveries or overrecoveries from the projected amounts are deferred and reflected in the BGSS tariff in subsequent periods.

Sales tax was calculated at 6 percent of revenue for fiscal years 2005 and 2004, as well as through July 14, 2006. On July 15, 2006, the sales tax was raised to 7 percent of revenue. The sales tax calculation excludes sales to cogeneration facilities, other utilities, off-system sales and federal accounts.

TEFA, which is included in Energy and other taxes on the Consolidated Statements of Income, is calculated on a per-therm basis and excludes sales to cogeneration facilities, other utilities and off-system sales. TEFA represents a regulatory allowed assessment imposed on all energy providers in the state. In 1998, along with the state sales tax and a state income tax, TEFA replaced the utility gross receipts tax formula. Previously, non-utility providers of energy were not subject to the gross receipts and franchise tax.

Regulatory rider expenses consist of recovery of state-mandated programs and the remediation adjustment clause costs. These expenses are designed to be offset by corresponding revenues and are calculated on a per-therm basis.

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

NJNG's operating revenues remained flat at approximately $1.1 billion in both fiscal 2006 and 2005, after having increased from $928.9 million, an increase of 22.5 percent, in fiscal 2004. The minimal change in operating revenue from fiscal 2006 as compared to fiscal 2005 is the net effect of:

- an increase in operating revenues associated with firm sales of $83.3 million due primarily to BGSS rates being adjusted in fiscal 2006 to provide provisional rate relief to NJNG in light of the volatile wholesale natural gas market; fully offset by
- a decrease due to a BGSS customer refund of approximately $23.7 million, which is inclusive of a sales tax refund of $1.3 million, as a result of lower cost of gas purchases achieved through a successful natural gas commodity purchasing strategy and declining wholesale natural gas market prices; and
- a decrease in off-system sales in the amount of $59 million, which was primarily the result of a decrease in volume sold, partially offset by an increase in the average price of natural gas in comparison to fiscal 2005 levels.

The increase in operating revenue in fiscal 2005 from fiscal 2004 was the result of higher prices due primarily to the increase in wholesale natural gas commodity costs.

Gas purchases increased less than 1 percent to $847.3 million in fiscal 2006, as compared with $846.4 million in fiscal 2005. The $900,000 increase in fiscal 2006 was due primarily to increased average gas prices offset by decreased volumes purchased. Gas purchases increased 27.6 percent in fiscal 2005 as compared with fiscal 2004 purchases of $663.4 million. The increase in fiscal 2005 was the result of higher prices due primarily to the increase in wholesale natural gas commodity costs as a result of several significant weather events that impacted short-term natural gas supplies.

Sales tax and TEFA, which are included in both Revenues and Energy and other taxes in the Consolidated Statements of Income, totaled $ million, $50.5 million and $45.2 million in fiscal 2006, 2005 and 2004, respectively. This increase in fiscal 2006 as compared with fiscal 2. is due primarily to an increase in operating revenue from firm sales to $799 million in fiscal 2006 from $741 million in fiscal 2005. Due to its being in effect since mid-July, the one percent increase in sales tax mandated by the state of New Jersey did not materially impact the increase. The increase in sales tax and TEFA in fiscal 2005 was due primarily to higher operating revenue from firm sales of $741 million in fiscal 2005 from $644 million in fiscal 2004.

Regulatory rider expenses totaled $28.6 million, $31.6 million and $9.5 million in fiscal 2006, 2005, and 2004, respectively. The decrease in regulatory rider expenses in fiscal 2006 is a direct result of the decrease in firm throughput through the NJNG natural gas distribution system. The increase in regulatory rider expense in fiscal 2005 is due primarily to higher rates associated with the remediation and Clean Energy riders.

Utility gross margin is comprised of three major categories:

- Utility Firm Gross Margin, which is derived from residential and commercial customers who receive natural gas service from NJNG through either sales or transportation tariffs;

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

- Incentive programs, where revenues generated or savings achieved from BPU-approved off-system sales, capacity release, Financial Risk Management (defined in *Incentive Programs,* below) or storage incentive programs are shared between customers and NJNG; and
- Utility gross margin from interruptible customers who have the ability to switch to alternative fuels and are subject to BPU-approved incentives.

Utility Firm Gross Margin

Utility gross margin from residential and commercial customers was impacted by the WNC, which provided for a revenue adjustment if the weather varied by more than one-half percent from normal weather (i.e., 20-year average). The accumulated adjustment from one heating season (i.e., October through May) was billed or credited to customers in subsequent periods. This mechanism reduced the variability of both customers' bills and NJNG's earnings due to weather fluctuations.

The WNC did not, however, reflect reductions in customer usage from the assumed level in the WNC. These reductions related to customer usage will be captured in NJNG's newly approved CIP tariff effective in fiscal 2007.

Customers switching between sales service and transportation service affect the components of utility gross margin from firm customers. NJNG's total utility gross margin is not negatively affected by customers who use its transportation service and purchase natural gas from another supplier because its tariff is designed so that no profit is earned on the commodity portion of sales to firm customers. All customers who purchase natural gas from another supplier continue to use NJNG for transportation service.

Total utility firm gross margin decreased $1.0 million, or less than 1 percent, and $1.2 million, or less than 1 percent, in fiscal 2006 and 2005, respectively. The change in fiscal 2006 was due primarily to the net effect of:

- the decrease in natural gas used by customers, as the winter heating season was 11.4 percent warmer compared with fiscal 2005;
- a reduction in customer usage per degree day over the same period in fiscal 2005; partially offset by
- an increase in fixed revenue as a result of customer growth; and
- the impact of the WNC.

The decrease in fiscal 2005 in comparison with fiscal 2004, was due primarily to a reduction in customer usage per degree day.

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

NJNG added 10,159 and 10,435 new customers and added natural gas heat and other services to another 874 and 929 existing customers in fiscal 2006 and 2005, respectively. This customer growth represents an estimated annual increase of approximately 1.6 billion cubic feet (Bcf) in sales to firm customers, assuming normal weather and usage.

The weather in fiscal 2006 was 9.9 percent warmer than normal, therefore NJNG accrued $10.3 million of utility gross margin for future recovery under the WNC. In fiscal 2005, the weather was 1.5 percent colder than normal, therefore NJNG deferred $2.1 million of gross margin for future refunds to customers under the WNC. The weather in fiscal 2004 was 1.1 percent warmer than normal, which resulted in no deferral or accrual of utility gross margin. On October 25, 2006, NJNG filed supporting documentation for the fiscal 2006 WNC surcharge and proposed the required rate increase of approximately 1.3 percent be effective on January 1, 2007.

Utility firm gross margin from sales to residential and commercial customers decreased $642,000, or less than 1 percent, and increased $503,000, or less than 1 percent, in fiscal 2006 and fiscal 2005, respectively. Sales to residential and commercial customers were 49.8 Bcf in fiscal 2006, compared with 55.0 Bcf in fiscal 2005 and 2004, respectively. The decrease in utility firm gross margin in fiscal 2006 compared with fiscal 2005 was due primarily to a warmer winter season, along with the lower usage per degree day, which was partially offset by customer growth. The increase in utility firm gross margin in fiscal 2005 from 2004 was due primarily to customer growth and colder than normal temperatures, partially offset by lower usage per degree day.

Utility firm gross margin from transportation service decreased $359,000, or 1.6 percent, and $1.7 million, or 6.9 percent, in fiscal 2006 and fiscal 2005, respectively. NJNG transported 7.4 Bcf for its firm customers in fiscal 2006, compared with 7.6 Bcf in fiscal 2005 and 8.4 Bcf in fiscal 2004. The decreases were due primarily to a reduction in customers utilizing the transportation service as a result of warmer weather and lower usage per degree day discussed above.

The following table shows residential and commercial customers using transportation services as of the end of each fiscal year:

	September 30,		
	2006	2005	2004
Residential	**8,594**	11,723	12,619
Commercial	**4,280**	3,523	3,768
Total	**12,874**	15,246	16,387

The decrease in transportation customers for all fiscal years was due primarily to a decline in third-party marketing efforts in NJNG's service territory. The increase in commercial customers for all fiscal years, was due primarily to the change to monthly based pricing.

In fiscal 2007 and 2008, NJNG currently expects to add approximately 9,900 and 10,400, new customers, respectively, and convert an additional 700 existing customers each year to natural gas heat and other services. Achieving these expectations would represent an estimated annual customer growth rate of approximately 2.2 percent and result in an estimated sales increase of approximately 1.5 Bcf annually. It is believed that this growth would increase utility gross margin under present base

rates by approximately $4.8 million annually, as calculated under NJNG's CIP tariff, which is effective October 1, 2006.

These growth expectations are based upon management's review of local planning board data, recent market research performed by third parties, builder surveys and studies of population growth rates in NJNG's service territory. However, future sales will be affected by the weather, actual energy usage patterns of NJNG's customers , economic conditions in NJNG's service territory, conversion and conservation activity, the impact of changing from a regulated to a competitive environment, changes in state regulation and other marketing efforts, as has been the case in prior years.

Incentive Programs

To reduce the overall cost of its natural gas supply commitments, NJNG has entered into contracts to sell natural gas to wholesale customers outside its franchise territory when the natural gas is not needed for system requirements. These off-system sales enable NJNG to spread its fixed demand costs, which are charged by pipelines to access their supplies year-round, over a larger and more diverse customer base. The off-system sales program includes an incentive mechanism which shares the gains and losses on the program between customers and shareowners on an 85 percent and 15 percent basis, respectively. NJNG also participates in the capacity release market on the interstate pipeline network when the capacity is not needed for its firm system requirements.

The financial risk management (FRM) program is designed to provide price stability to NJNG's natural gas supply portfolio. The FRM program includes an incentive mechanism designed to encourage the use of financial instruments to hedge NJNG's natural gas costs, with a sharing of the costs and results between customers and shareowners, on an 80 percent and 20 percent basis, respectively.

The storage incentive program shares gains and losses between customers and shareowners, on an 80 percent and 20 percent basis, respectively. This program measures the difference between the actual cost of natural gas in storage and a benchmark applicable to the April-t' ?h-October injection season.

On April 12, 2006, the BPU approved an agreement whereby the existing utility gross margin-sharing programs between customers and shareowners were extended through October 31, 2007.

NJNG's incentive programs totaled 38.4 Bcf and generated $7.4 million of utility gross margin in fiscal 2006, compared with 52.4 Bcf and $6.1 million of utility gross margin in fiscal 2005 and 47.1 Bcf and $5.8 million of utility gross margin in fiscal 2004. Utility gross margin from incentive programs comprised 4 percent of total utility gross margin in fiscal 2006 and 3 percent of total utility gross margin in 2005 and 2004, respectively. The increases in utility gross margin in fiscal 2006 and 2005, were primarily due to the FRM and the storage incentive programs, which both benefited from additional volatility in the wholesale energy market.

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

Interruptible

NJNG serves 48 customers through interruptible sales and/or transportation tariffs. Sales made under the interruptible sales tariff are priced on market-sensitive energy parity rates. Although therms sold and transported to interruptible customers represented 7 percent of total throughput in fiscal 2006, 7.8 percent of total throughput in fiscal 2005 and 7.5 percent of the total throughput in fiscal 2004, they accounted for less than 1 percent of the total utility gross margin in each year due to the sharing formulas that govern these sales. Under these formulas, NJNG retains 10 percent of the utility gross margin from interruptible sales and 5 percent of the utility gross margin from transportation sales, with 90 percent and 95 percent, respectively, credited to firm sales customers through the BGSS. Interruptible sales were 2.0 Bcf and 2.9 Bcf in fiscal 2006 and 2005, respectively. In addition, NJNG transported 5.2 Bcf and 6.8 Bcf in fiscal 2006 and 2005, respectively, for its interruptible customers.

Operation and Maintenance Expense

Operation and maintenance expense increased $8.4 million, or 10.9 percent, in fiscal 2006 as compared with fiscal 2005. The increase was due primarily to higher regulatory costs, increased labor costs and an increase in bad debt expense. Higher regulatory costs are due primarily to the new CIP program costs and higher BPU assessments. Increased labor costs are due primarily to annual wage increases and the absence of certain credits associated with incentive compensation benefits in the prior year that did not recur in the current year. Increased bad debt expense is due primarily to increased natural gas prices. Operation and maintenance expense decreased $910,000, or 1.2 percent, in fiscal year 2005, compared with fiscal year 2004, due primarily to lower costs associated with incentive compensation plans, decreased labor costs and lower information technology maintenance costs, which more than offset NJNG's share of the early retirement charge.

Depreciation Expense

Depreciation expense increased $1.2 million in fiscal 2006 and $1.1 million in fiscal 2005 due primarily to utility plant additions of $53.1 million and $52.8 million, respectively.

Operating Income

Operating income decreased $9.4 million, or 9.7 percent, in fiscal 2006, compared with fiscal 2005, due primarily to higher Operation and maintenance expense, and higher depreciation expense, as described above. Operating income decreased $1.3 million, or 1.3 percent, in fiscal 2005 compared with fiscal 2004, due primarily to the lower gross margin and higher depreciation expense, partially offset by lower Operation and maintenance expense, as described above.

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

Interest Charges

Interest charges increased $2.2 million in fiscal 2006 compared to fiscal 2005 due primarily to higher average interest rates on variable rate long- and short-term debt and interest costs payable to customers on overrecovered BGSS balances. In fiscal 2005, interest increased $1.5 million reflecting higher average interest rates on both long- and short-term debt.

Net Income

Net income decreased $6.5 million, or 12.2 percent, in fiscal 2006, compared with fiscal 2005, due primarily to lower operating income and higher interest expense as previously discussed. Net income decreased $2.1 million, or 3.9 percent, in fiscal 2005, compared with fiscal 2004, due primarily to lower operating income discussed above, lower other income due to reduced interest income earned on various deferred regulatory riders and higher interest expense as previously discussed.

Energy Services Operations

NJRES' financial results are summarized as follows:

(Thousands)	2006	2005	2004
Operating revenues	$ 2,133,540	$ 1,973,268	$ 1,582,103
Gas purchases	2,062,513	1,933,970	1,549,938
Gross margin	71,027	39,298	32,165
Operation and maintenance expense	16,415	6,909	6,987
Depreciation and amortization	211	253	204
Other taxes	656	710	106
Operating income	$ 53,745	$ 31,426	$ 24,868
Other income	$ 998	$ 578	$ (767)
Interest charges, net	$ 7,042	$ 4,137	$ 1,156
Net income	$ 28,113	$ 16,483	$ 13,572

NJRES' operating revenues increased $160.3 million, or 8.1 percent, in fiscal 2006 as compared with fiscal 2005 and increased $391.2 million in fiscal 2005, as compared with fiscal 2004, due primarily to higher natural gas prices. Natural gas sold and managed by NJRES totaled 228.7 Bcf in fiscal 2006, compared with 254.7 Bcf in fiscal 2005 and 263.3 Bcf in fiscal 2004.

NJRES' gross margin is defined as natural gas revenues and management fees less natural gas purchases, which include fixed demand costs. NJRES' gross margin increased $31.7 million in fiscal 2006, as compared with fiscal 2005, due primarily to favorable time spreads on larger storage asset positions, as well as, securing positive locational spreads on transportation capacity, and the benefit in market price changes from certain natural gas basis swaps, which concluded in October 2006, that were not deemed effective cash flow hedges, under SFAS 133.

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

NJRES' gross margin increased $7.1 million in fiscal 2005 compared with fiscal 2004, due primarily to favorable time spreads on storage asset positions, as well as to favorable locational spreads on transportation capacity.

NJRES' Operation and maintenance expense increased $9.5 million in fiscal 2006 as compared with fiscal 2005, due primarily to higher labor costs incurred to support earnings growth associated with operational expansion and increased charitable contributions. Operation and maintenance expense remained relatively consistent in fiscal 2005 as compared with fiscal 2004.

NJRES' net income increased $11.6 million in fiscal 2006, as compared with fiscal 2005, and $2.9 million in fiscal 2005, as compared with fiscal 2004, due primarily to the increase in gross margin described above.

Future results are subject to NJRES' ability to maintain and expand its wholesale marketing activities and are contingent upon many other factors, including an adequate number of appropriate counterparties, volatility in the natural gas market, sufficient liquidity in the energy trading market and continued access to the capital markets.

Retail and Other Operations

The consolidated financial results of Retail and Other are summarized as follows:

(Thousands)	2006	2005	2004
Operating revenues	**$ 27,568**	$ 36,900	$ 22,698
Other income	**$ 3,301**	$ 3,731	$ 2,029
Net income	**$ 3,536**	$ 6,481	$ 2,478

Operating revenues in fiscal 2006 decreased $9.3 million compared to fiscal 2005 due primarily to the sale of a commercial office building owned by CR&R in fiscal 2005 that did not recur in fiscal 2006. Excluding the impact of this sale, fiscal 2006 operating revenues increased approximately $800,000 due to an increase in NJRHS appliance service contracts and installations. Operating revenues increased $14.2 million in fiscal 2005 compared with fiscal 2004, due primarily to the sale of a commercial office building as well as the sale of other commercial real estate property and increased service contracts and installations.

Other income includes the amortization of a gain related to the sale-leaseback of a building, entered into in fiscal 1996, and pre-tax earnings generated from NJR Energy's equity investment in Iroquois of $2.0 million, $1.7 million and $1.2 million in fiscal 2006, 2005 and 2004 respectively.

Net income in fiscal 2005, included a $6 million after-tax gain on the sale of the commercial office building, partially offset by the $2.5 million after-tax loss on the impairment of 52 acres of undeveloped land. Net of these items and this segment's portion of the early retirement charge, earnings in fiscal 2005 totaled $3.3 million. Excluding these items, net income increased by $300,000 in fiscal 2006, as compared with fiscal 2005, due primarily to improved operating results at NJRHS and by $900,000 in fiscal 2005, as compared with fiscal 2004, due to higher earnings in Iroquois and gains on the sale of other equity investments.

1 17. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued)

Liquidity and Capital Resources

Consolidated

NJR's objective is to maintain a consolidated capital structure that reflects the different characteristics of each business segment and provides adequate financial flexibility for accessing capital markets as required.

NJR's consolidated capital structure at September 30 was as follows:

	2006	2005	2004
Common stock equity	**50%**	47%	44%
Long-term debt	**27**	34	29
Short-term debt	**23**	19	27
Total	**100%**	100%	100%

NJR satisfies its external common equity requirements, if any, through issuances of its common stock, including the proceeds from stock issuances under its Automatic Dividend Reinvestment Plan (DRP) and proceeds from the exercise of options issued under the Company's long-term incentive program. The DRP allows NJR, at its option, to use shares purchased on the open market or newly issued shares.

The Company currently has a 3.5 million share repurchase plan. As of September 30, 2006, the Company had repurchased 3.15 million shares of its common stock under this plan.

In December 2004 , NJR entered into a $275-million committed credit facility with several banks, with a 3-year term expiring in
l aber 2007. In November 2005, NJR amended the facility to increase it to $325 million.

In October 2006, NJRES entered into a 3-year $30 million committed credit facility with a multinational financial institution. Borrowings under this facility are guaranteed by NJR.

These facilities provide liquidity to meet working capital and external debt-financing requirements of NJR and its nonregulated companies. Neither NJNG nor its assets are obligated or pledged to support the NJR or NJRES facilities .

NJR's short-term debt at September 30, 2006, which is primarily on behalf of NJRES, decreased to $129.2 million from $174.1 million at September 30, 2005. The decrease is due primarily to reduced margin calls, which were a result of increased over-the-counter transactions and lower gas prices. NJRES' use of high-injection, high-withdrawal storage facilities and anticipated pipeline park-and-loan arrangements, combined with related hedging activities in the volatile wholesale natural gas market, create significant short-term cash requirements, which are funded by NJR.

NJR borrows under its committed credit facilities to fund the debt requirements of its nonregulated subsidiaries and its working capital and investment activity. NJR currently anticipates that its financing requirements in fiscal 2007 and 2008 will be met through internally generated cash and the issuance of long- and short-term debt.

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

Financial covenants contained in NJR's credit facility include a maximum debt-to-total capitalization of 65 percent and minimum interest coverage ratio of 2.5. At September 30, 2006, the debt-to-total capitalization was 52 percent, and for the year ended September 30, 2006, the interest coverage ratio, as defined in the credit facility, was 7.

NJNG satisfies its debt requirements by issuing long- and short-term debt based upon its own financial profile. NJNG does not guarantee or otherwise directly support the debt of NJR. The seasonal nature of NJNG's operations creates large short-term cash requirements, primarily to finance natural gas purchases and customer accounts receivable. NJNG obtains working capital for these requirements, and for the temporary financing of construction and MGP remediation expenditures and energy tax payments, through the issuance of its commercial paper and short-term bank loans.

To support the issuance of commercial paper in December 2004, NJNG entered into a $225 million committed credit facility with several banks, with a 5-year term, expiring in December 2009. In November 2005, NJNG amended this facility to increase it to $250 million. NJNG had $151.5 million of commercial paper borrowings supported by NJNG's committed credit facilities as of September 30, 2006 and no commercial paper borrowings as of September 30, 2005.

NJNG has received approximately $4.1 million, $4.9 million and $3.9 million in fiscal 2006, 2005 and 2004, respectively, related to the sale-leaseback of a portion of its gas meters. NJNG also plans to continue its meter sale-leaseback program at approximately $5 million annually.

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

The following table is a summary of NJR contractual cash obligations and their applicable payment due dates:

(Thousands)

		Payments Due by Period			
Contractual Obligations	Total	Up to 1 Year	2-3 Years	4-5 Years	After 5 Years
Long-term debt *	$ 454,760	$ 12,815	$ 23,478	$ 73,619	$ 344,848
Capital lease obligations *	84,218	7,375	14,750	18,934	43,159
Operating leases *	8,914	2,967	3,788	1,368	791
Short-term debt	280,700	280,700	—	—	—
Clean energy program*	20,498	1,957	18,541	—	—
Construction obligations	5,421	5,421	—	—	—
Natural gas supply purchase obligations–NJNG	548,285	160,693	153,406	125,971	108,215
Natural gas supply purchase obligations–NJRES	310,454	191,968	70,544	32,492	15,450
Total contractual cash obligations	$ 1,713,250	$ 663,896	$ 234,507	$ 252,384	$ 512,463

* *These obligations include an interest component.*

As of September 30, 2006, there were NJR guarantees covering approximately $232 million of natural gas purchases and demand fee commitments of NJRES and NJNG, included in natural gas supply purchase obligations above, not yet reflected in Accounts payable on the Consolidated Balance Sheet.

As of September 30, 2006, NJR had a $4.0 million letter of credit outstanding on behalf of NJRES, which will expire on August 1, 2007, in conjunction with a long-term natural gas storage agreement

At September 30, 2006, NJR had a $675,000 letter of credit outstanding on behalf of CR&R, which will expire on December 3, 2007, in conjunction with development activities.

These letters of credit reduce the amount available under NJR's committed credit facility by the same amount. NJR does not anticipate that these letters of credit will be drawn upon by the counterparties and they will be renewed as necessary. NJR expects to renew these letter of credit agreements upon their expiration.

As of September 30, 2006, NJNG had a $45 million letter of credit outstanding which will expire on December 31, 2006, in conjunction with a long-term swap agreement. The long-term swap agreement was entered into as a hedge related to an offsetting physical purchase of natural gas for the same time period and volume. This letter of credit reduces the amount available under NJNG's committed credit facility by the same amount. NJNG does not anticipate that this letter of credit will be drawn upon by the counterparty and it will be renewed as necessary upon its expiration.

I. 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Continued)

The Company made a discretionary $10 million tax-deductible contribution to its pension plans in fiscal 2006. The Company is not currently required to make minimum pension funding contributions during fiscal 2007. If market performance is less than anticipated, additional funding may be required.

In fiscal 2006, $3.7 million of tax-deductible discretionary contributions were made to the Other Postemployment Benefit (OPEB) plans. The Company's funding level to its OPEB plans is expected to be approximately $600,000 annually over the next five years. Additional contributions to the pension and OPEB Plans may be made based on market conditions and various assumptions.

Off-Balance-Sheet Arrangements

The Company does not have any off-balance-sheet financing arrangements.

Cash Flow

Operating Activities

Cash flow used in operations totaled $22.9 million in fiscal 2006, compared with cash flow from operations of $204.8 million in fiscal 2005 and cash flow used in operations of $50.1 million in fiscal 2004. The decrease of approximately $228 million in fiscal 2006, as compared with fiscal 2005, was due primarily to changes in working capital and higher MGP expenditures, which were partially offset by higher net income and a lower gain on asset sale. The reduction in cash flow from working capital was due primarily to the increase in gas in storage and a decrease in gas purchases payable, which were caused by higher storage volumes and wholesale gas commodity costs, partially offset by a decrease in accounts receivable, primarily as the result of BGSS customer credits in September 2006. The increase in fiscal 2005, as compared with fiscal 2004, was due primarily to higher net income and improved working capital. The improvement in working capital was due primarily t' reduction in broker margin requirements and underrecovered gas costs, which was partially offset by an increase in accounts receivable.

NJNG's MGP expenditures, exclusive of insurance recoveries, are currently expected to total $30.4 million and $17.6 million in fiscal 2007 and 2008, respectively.

Financing Activities

Cash flow provided by financing activities totaled $74.0 million in fiscal 2006, compared with cash flows used in financing activities of $157.7 million in fiscal 2005 and cash flows provided by financing activities of $139.8 million in fiscal 2004. The change in fiscal 2006 was due primarily to an increase in amount of short-term debt utilized, increased issuance of long-term debt and increased proceeds from the exercise of stock options partially offset by higher common stock repurchases. The change in fiscal 2005 was due primarily to the payment of long-term debt, greater share repurchases and a reduction in short-term debt.

In March 2004, NJNG issued $60 million of Unsecured Senior Notes with a 10-year maturity and 4.77 percent interest rate and NJR issued $25 million of Unsecured Senior Notes with a 5-year

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

maturity and 3.75 percent interest rate. Neither NJNG nor its assets are obligated or pledged to support the NJR notes.

In December 2003, NJNG entered into a loan agreement under which the New Jersey Economic Development Authority (EDA) loaned NJNG the proceeds from its $12 million, 5% Natural Gas Facilities Revenue Bonds, which NJNG deposited into a construction fund and which are supported by NJNG's 5% Series HH Bonds. NJNG drew down $1.5 million, $6.3 million and $4.2 million in September 2005, December 2004 and December 2003, respectively , from the construction fund.

In October 2005, NJNG entered into a loan agreement under which the EDA loaned NJNG the proceeds from $35.8 million of tax-exempt EDA Bonds consisting of $10.3 million 4.5% (Series 2005A) and $10.5 million 4.6% (Series 2005B) Revenue Refunding Bonds, and $15 million 4.9% (Series 2005C) Natural Gas Facilities Revenue Bonds. NJNG used the proceeds from the Series A and B bonds to refinance NJNG's $10.3 million 5.38% Series W First Mortgage Bonds and its $10.5 million 6.25% Series Y First Mortgage Bonds, respectively.

The entire $15 million proceeds from the Series 2005C bonds were deposited into a construction fund. The Series 2005C Bonds are supported by NJNG's 4.9% Series KK Bonds that mature on October 1, 2040. NJNG immediately drew down $2.5 million from the construction fund in October 2005 and an additional $4.0 million in September 2006.

Investing Activities

Cash flows used in investing activities totaled $71.1 million in fiscal 2006, compared with $27.2 million and $86.5 million in fiscal 2005 and 2004, respectively. The change in fiscal 2006 was due primarily to the cash proceeds from a commercial office building sale in fiscal 2005, which did not recur in fiscal 2006 and additional deposits in the construction fund associated with the EDA financing agreement, partially offset by the absence of additional equity investments. The change in fiscal 2005 was due primarily to the $30.6 million in cash proceeds generated from the sale of a commercial office building, a reduction in capital expenditures and the drawdown of $7.8 million from the construction fund created under the EDA financing arrangement. These improvements were partially offset by an $8.7 million equity investment to increase the Company's ownership interest in Iroquois.

The Company's capital expenditures for fiscal 2004 through fiscal 2006 and projected capital requirements for fiscal years 2007 and 2008 are as follows:

(Thousands)	2008	2007	2006	2005	2004
NJNG	$ 63,333	$ 65,599	**$ 60,559**	$ 59,303	$ 65,355
Energy Services	200	200	**244**	774	38
Retail and Other	200	4,600	**5,490**	823	13,266
Total	$ 63,733	$ 70,399	**$ 66,293**	$ 60,900	$ 78,659

NJNG's capital expenditures result primarily from the need for services, mains and meters to support its continued customer growth, pipeline safety rulemaking and general system improvements. NJNG's capital expenditures are expected to increase in fiscal 2007 and 2008 when compared to the

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

capital spending in fiscal 2006, due primarily to system integrity and expected replacement needed under pending pipeline safety rulemaking.

NJRES does not currently anticipate any significant capital expenditures in fiscal 2007 and 2008.

Retail and Other capital expenditures each year were primarily made in connection with investments aimed at developing its real estate holdings. At September 30, 2006, CR&R owned 99 acres of undeveloped land and 5 acres of land currently under development. In fiscal 2006, capital expenditures of $5.5 million were primarily related to CR&R's construction of a 56,400-square-foot office building. In December 2004, CR&R sold a 200,000 square-foot office building, which generated $30.6 million in proceeds and resulted in a $10.1 million pre-tax gain. Other real estate sales generated proceeds of $2 million.

Retail and Other's anticipated capital expenditures of $4.6 million in fiscal 2007 are primarily related to CR&R's construction and completion of a 56,400 square-foot office building.

Credit Ratings

The table below summarizes NJNG's credit ratings issued by two rating entities, Standard and Poor's (S&P) and Moody's Investors Service, Inc. (Moody's) as of September 30, 2006:

	S & P	Moody's
Corporate Rating	A+	N/A
Commercial Paper	A-1	P-1
Senior Secured	AA-	Aa3
Ratings Outlook	Negative	Stable

NJNG's S&P and Moody's Senior Secured ratings are investment-grade ratings and represent the sixth highest rating within the investment grade category. Moody's and S&P give NJNG's commercial paper the highest rating within the Commercial Paper investment-grade category. Investment-grade ratings are generally divided into three groups: high, upper medium and medium. NJNG's senior secured ratings and the commercial paper ratings fall into the high group. NJR is not a rated entity.

NJNG is not party to any lending agreements that would accelerate the maturity date of any obligation caused by a failure to maintain any specific credit rating. A rating set forth above is not a recommendation to buy, sell or hold the Company's or NJNG's securities and may be subject to revision or withdrawal at any time. Each rating set forth above should be evaluated independently of any other rating.

The timing and mix of any external financings will target a common equity ratio that is consistent with maintaining the Company's current short- and long-term credit ratings.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Financial Risk Management

Commodity Market Risks

Natural gas is a nationally traded commodity, and its prices are determined effectively by the New York Mercantile Exchange (NYMEX) and over-the-counter markets. The prices on the NYMEX and over-the-counter markets generally reflect the notional balance of natural gas supply and demand, but are also influenced significantly from time to time by other events.

The regulated and unregulated natural gas businesses of the Company and its subsidiaries are subject to market risk due to fluctuations in the price of natural gas. To hedge against such fluctuations, the Company and its subsidiaries have entered into futures contracts, options agreements and swap agreements. To manage these instruments, the Company has well-defined risk management policies and procedures that include daily monitoring of volumetric limits and monetary guidelines. The Company's natural gas businesses are conducted through three of its operating subsidiaries. First, NJNG is a regulated utility that uses futures, options and swaps to hedge against price fluctuations and its recovery of natural gas costs is governed by the BPU. Second, NJRES uses futures, options and swaps to hedge purchases and sales of natural gas. Finally, NJR Energy has entered into two swap transactions to hedge an 18-year fixed-price contract to sell remaining volumes of approximately 9.7 Bcf of natural gas (Gas Sales Contract) to an energy marketing company. NJR Energy has hedged both the price and physical delivery risks associated with the Gas Sales Contract.

The following table reflects the changes in the fair market value of commodity derivatives from September 30, 2005, to September 30, 2006:

(Thousands)	Balance September 30, 2005	Increase (Decrease) in Fair Market Value	Less Amounts Settled	Balance September 30, 2006
NJNG	$ 35,135	$ (63,345)	$ 54,241	$ (82,451)
NJRES	(155,029)	227,082	(44,494)	116,547
NJR Energy	63,745	(23,758)	4,564	35,423
Total	$ (56,149)	$ 139,979	$ 14,311	$ 69,519

There were no changes in methods of valuations during the year ended September 30, 2006.

The following is a summary of fair market value of commodity derivatives at September 30, 2006, by method of valuation and by maturity for each fiscal year period:

(Thousands)	2007	2008-2010	After 2010	Total Fair Value
Price based on NYMEX	$ 59,838	$ 4,562	$ (336)	$ 64,064
Price based on over-the-counter published quotations and models	(42)	5,497	—	5,455
Total	$ 59,796	$ 10,059	$ (336)	$ 69,519

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Continued)

The following is a summary of commodity derivatives by type as of September 30, 2006:

		Volume (Bcf)	Price per Mmbtu	Amounts Included in Derivatives (Thousands)
NJNG	Futures	18.4	$ 4.335-$10.100	$ (3,231)
	Options	(8.9)	$ 7.000-$12.000	1,747
	Swaps	(11.7)	$ 3.799-$10.128	(80,967)
NJRES	Futures	(0.9)	$ 4.314-$12.040	10,530
	Options	—	$ 8.400-$17.000	55
	Swaps	(79.5)	$ 3.866-$11.515	105,962
NJR Energy	Swaps	10.4	$ 3.068-$4.406	35,423
Total				$ 69,519

The Company uses a value-at-risk (VaR) model to assess the market risk of its net futures, swaps and options positions. The VaR at September 30, 2006, using the variance-covariance method with a 95 percent confidence level and a 1-day holding period, was $600,000. The VaR with a 99 percent confidence level and a 10-day holding period was $2.5 million. The calculated VaR represents an estimate of the potential change in the value of the net positions. These estimates may not be indicative of actual results because actual market fluctuations may differ from forecasted fluctuations.

Wholesale Credit Risk

NJNG, NJRES and NJR Energy engage in wholesale marketing activities. NJR monitors and manages the credit risk of its wholesale marketing operations through credit policies and procedures that management believes reduce overall credit risk. These policies include a review and evaluation of prospective counterparties' financial statements and/or credit ratings, daily monitoring of counterparties' credit limits, daily communication with traders regarding credit status and the use of credit mitigation measures, such as minimum margin requirements, collateral requirements and netting agreements. Examples of collateral include letters of credit and cash received for either prepayment or margin deposit.

The Company's Risk Management Committee (RMC) continuously monitors NJR's credit risk management policies and procedures. The RMC is a group of senior officers from NJR-affiliated companies that meets twice a month and, among other things, evaluates the effectiveness of existing credit policies and procedures, reviews material transactions and discusses emerging issues.

Following is a summary of gross and net credit exposures, grouped by investment and noninvestment grade counterparties, as of September 30, 2006. Gross credit exposure is defined as the unrealized fair value of derivative and energy trading contracts plus any outstanding receivable for the value of natural gas delivered for which payment has not yet been received. Net credit exposure is defined as gross credit exposure reduced by collateral received from counterparties and/or payables, where netting agreements exist. The amounts presented below exclude accounts receivable for retail natural gas sales and services.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Continued)

Unregulated counterparty credit exposure as of September 30, 2006, is as follows:

(Thousands)	Gross Credit Exposure	Net Credit Exposure
Investment grade	$ 213,013	$ 194,239
Noninvestment grade	5,735	705
Internally rated investment grade	9,613	8,553
Internally rated noninvestment grade	4,884	—
Total	$ 233,245	$ 203,497

NJNG's counterparty credit exposure as of September 30, 2006, is as follows:

(Thousands)	Gross Credit Exposure	Net Credit Exposure
Investment grade	$ 10,808	$ 8,353
Noninvestment grade	211	—
Internally rated investment grade	1,601	1,247
Internally rated noninvestment grade	420	—
Total	$ 13,040	$ 9,600

Due to the inherent volatility in the prices of natural gas commodities and derivatives, the market value of contractual positions with individual counterparties could exceed established credit limits or collateral provided by those counterparties. If a counterparty failed to perform the obligations under its contract (for example, failed to deliver or pay for natural gas), then the Company could sustain a loss. This loss would comprise the loss on natural gas delivered but not paid for and/or the cost of replacing natural gas not delivered at a price higher than the price in the original contract. Any such loss could have a material impact on the Company's financial condition, results of operations or cash flows.

Interest Rate Risk–Long-Term Debt

At September 30, 2006, the Company (excluding NJNG) had no variable-rate long-term debt.

At September 30, 2006, NJNG had total variable-rate, tax-exempt long-term debt of $97.1 million, which is hedged by interest rate caps expiring in July 2009 that limit NJNG's variable-rate debt exposure from the tax-exempt EDA bonds at 4.5 percent.

Effects of Inflation

Although inflation rates have been relatively low to moderate in recent years, any change in price levels has an effect on operating results due to the capital-intensive and regulated nature of the Company's principal subsidiary. The Company attempts to minimize the effects of inflation through cost control, productivity improvements and regulatory actions where appropriate.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control over Financial Reporting

Management of New Jersey Resources (NJR or the Company) is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13A-15 (f) and 15d-15 (f) of the Securities and Exchange Act of 1934. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors as to the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements, errors or fraud. Also, projections of any evaluations of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2006. In making this assessment, management used criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on this assessment, management concluded that as of September 30, 2006, the Company's internal control over financial reporting is operating as designed and is effective based on the COSO criteria.

Our independent registered public accounting firm, Deloitte & Touche LLP, has issued its report on our assessment of the Company's internal control over financial reporting as of September 30, 2006 which appears herein.

November 22, 2006

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
New Jersey Resources Corporation:

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that New Jersey Resources and subsidiaries (the "Company") maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, based on the criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and consolidated statement of capitalization of the Company as of September 30, 2006, the related consolidated statements of income, common stock equity and comprehensive income, and cash flows for the year ended September 30, 2006 and the consolidated financial statement schedule for the year ended September 30, 2006 listed in the index in Item 15, and our report dated November 22, 2006 expressed an unqualified opinion on those consolidated financial statements and consolidated financial statement schedule, and included an explanatory paragraph regarding the adoption of Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations.

/s/ DELOITTE & TOUCHE LLP
Parsippany, New Jersey

November 22, 2006

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
New Jersey Resources Corporation

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of New Jersey Resources Corporation and subsidiaries (the "Company") as of September 30, 2006 and 2005, and the related consolidated statements of income, common stock equity and comprehensive income, and cash flows for each of the three years in the period ended September 30, 2006. Our audits also included the consolidated financial statement schedule listed in the index in Item 15. These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of September 30, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects, the information set forth therein.

As discussed in Note 8 to the consolidated financial statements, on September 30, 2006, the Company adopted Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, based on the criteria established in Internal Control–Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated November 22, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Parsippany, New Jersey

November 22, 2006

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

CONSOLIDATED STATEMENTS OF INCOME

(Thousands, except per share data)

Fiscal Years Ended September 30,	2006	2005	2004
OPERATING REVENUES	**$ 3,299,608**	$ 3,148,262	$ 2,533,607
OPERATING EXPENSES			
Gas purchases	**2,909,789**	2,780,343	2,213,374
Operation and maintenance	**121,384**	108,071	101,118
Regulatory rider expenses	**28,587**	31,594	9,540
Depreciation and amortization	**34,753**	33,675	32,449
Energy and other taxes	**58,632**	56,211	49,908
Total operating expenses	**3,153,145**	3,009,894	2,406,389
OPERATING INCOME	**146,463**	138,368	127,218
Other income	**7,747**	7,359	5,696
Interest charges, net	**25,669**	20,474	15,395
INCOME BEFORE INCOME TAXES	**128,541**	125,253	117,519
Income tax provision	**50,022**	48,913	45,945
NET INCOME	**$ 78,519**	$ 76,340	$ 71,574
EARNINGS PER COMMON SHARE			
BASIC	**$ 2.82**	$ 2.77	$ 2.60
DILUTED	**$ 2.80**	$ 2.71	$ 2.55
DIVIDENDS PER COMMON SHARE	**$ 1.44**	$ 1.36	$ 1.30
WEIGHTED AVERAGE SHARES OUTSTANDING			
BASIC	**27,862**	27,591	27,530
DILUTED	**28,081**	28,121	28,053

See Notes to Consolidated Financial Statements

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Thousands)	2006	2005	2004
CASH FLOWS (USED IN) FROM OPERATING ACTIVITIES			
Net income	$ 78,519	$ 76,340	$ 71,574
Adjustments to reconcile net income to cash flows from operating activities			
Depreciation and amortization	34,753	33,675	32,449
Land impairment charge	—	3,895	—
Amortization of deferred charges	301	1,552	1,801
Unrealized (gain) loss on derivatives	(4,935)	3,056	2,006
Deferred income taxes	(11,896)	(2,406)	2,690
Manufactured gas plant remediation costs	(22,346)	(15,330)	(13,976)
Gain on asset sales	(617)	(11,818)	—
Contributions to employee benefit plans	(13,690)	(11,548)	(12,622)
Changes in:			
Working capital	(107,204)	120,548	(148,554)
Other noncurrent assets	(19,165)	1,381	11,495
Other noncurrent liabilities	43,287	5,477	3,037
Cash flows (used in) from operating activities	(22,993)	204,822	(50,100)
CASH FLOWS FROM (USED IN) FINANCING ACTIVITIES			
Proceeds from common stock	25,346	9,918	17,922
Tax benefit from stock options exercised	6,791	2,172	1,098
Proceeds from long-term debt	35,800	—	97,000
Proceeds from sale-leaseback transaction	4,090	4,904	3,941
Payments of long-term debt	(24,276)	(28,070)	(2,665)
Purchases of treasury stock	(40,883)	(23,835)	(1,164)
Payments of common stock dividends	(39,446)	(37,164)	(35,269)
Net proceeds (payments) related to short-term debt	106,600	(85,600)	58,900
Net cash flows from (used in) financing activities	74,022	(157,675)	139,763
CASH FLOWS USED IN INVESTING ACTIVITIES			
Expenditures for			
Utility plant	(53,060)	(52,801)	(60,313)
Real estate properties and other	(5,734)	(1,597)	(13,304)
Cost of removal	(7,499)	(6,502)	(5,042)
Equity investments	—	(8,764)	—
(Investment in) withdrawal from restricted cash construction fund	(8,500)	7,800	(7,800)
Proceeds from asset sales and available for sale investments	3,747	34,682	—
Cash flows used in investing activities	(71,046)	(27,182)	(86,459)
Change in cash and temporary investments	(20,017)	19,965	3,204
Cash and temporary investments at beginning of year	25,008	5,043	1,839
Cash and temporary investments at end of year	$ 4,991	$ 25,008	$ 5,043
CHANGES IN COMPONENTS OF WORKING CAPITAL			
Receivables	$ 96,769	$ (87,897)	$ (27,260)
Inventories	(250,765)	19,620	(86,953)
Underrecovered gas costs	38,759	32,456	10,737
Gas purchases payable	(3,107)	90,118	10,238
Prepaid and accrued taxes, net	6,808	2,135	(12,932)
Accounts payable and other	(3,294)	9,978	1,863
Restricted broker margin accounts	(18,437)	40,084	(31,660)
Other current assets	(11,675)	12,308	(8,098)
Other current liabilities	37,738	1,746	(4,489)
Total	$ (107,204)	$ 120,548	$ (148,554)
SUPPLEMENTAL DISCLOSURES OF CASH FLOWS INFORMATION			
Cash paid for			
Interest (net of amounts capitalized)	$ 22,186	$ 18,085	$ 12,353
Income taxes	$ 38,101	$ 47,812	$ 39,277

See Notes to Consolidated Financial Statements

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

CONSOLIDATED BALANCE SHEETS

ASSETS

(Thousands) September 30,	2006	2005
PROPERTY, PLANT AND EQUIPMENT		
Utility plant, at cost	$ 1,243,586	$ 1,197,418
Real estate properties and other, at cost	27,136	24,340
	1,270,722	1,221,758
Accumulated depreciation and amortization	(335,783)	(316,628)
Property, plant and equipment, net	934,939	905,130
CURRENT ASSETS		
Cash and temporary investments	4,991	25,008
Customer accounts receivable	133,615	235,338
Unbilled revenues	12,543	10,207
Allowance for doubtful accounts	(2,679)	(5,297)
Regulatory assets	8,105	34,904
Gas in storage, at average cost	512,942	254,909
Materials and supplies, at average cost	3,599	3,857
Prepaid state taxes	26,343	24,020
Derivatives, at fair value	223,559	359,540
Broker margin account	30,833	120,420
Other	11,665	10,304
Total current assets	965,516	1,073,210
NONCURRENT ASSETS		
Equity investments	27,208	27,649
Regulatory assets	322,986	231,366
Derivatives, at fair value	94,638	70,777
Prepaid pension	21,045	—
Restricted cash construction fund	8,500	—
Other	24,096	22,116
Total noncurrent assets	498,473	351,908
Total assets	$ 2,398,928	$ 2,330,248

See Notes to Consolidated Financial Statements

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

CAPITALIZATION AND LIABILITIES

(Thousands) September 30,	2006	2005
CAPITALIZATION		
Common stock equity	$ 621,662	$ 438,052
Long-term debt	332,332	317,204
Total capitalization	953,994	755,256
CURRENT LIABILITIES		
Current maturities of long-term debt	3,739	3,253
Short-term debt	280,700	174,100
Gas purchases payable	297,879	300,986
Accounts payable and other	46,823	54,683
Dividends payable	10,056	9,366
Accrued taxes	9,267	25,429
Regulatory liabilities	1,710	—
Clean energy program	8,244	6,078
Derivatives, at fair value	163,557	377,928
Broker margin account	14,220	122,244
Customers' credit balances and deposits	60,960	22,609
Total current liabilities	897,155	1,096,676
NONCURRENT LIABILITIES		
Deferred income taxes	227,100	104,809
Deferred investment tax credits	7,835	8,157
Deferred revenue	10,206	10,898
Derivatives, at fair value	85,036	107,883
Manufactured gas plant remediation	105,400	93,920
Postemployment employee benefit liability	4,497	5,867
Regulatory liabilities	64,220	118,147
Clean energy and conservation incentive programs	13,138	18,612
Asset retirement obligation	23,293	—
Other	7,054	10,023
Total noncurrent liabilities	547,779	478,316
Total Capitalization and Liabilities	$ 2,398,928	$ 2,330,248

See Notes to Consolidated Financial Statements

1. 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

CONSOLIDATED STATEMENTS OF CAPITALIZATION

(Thousands, except share amounts) September 30,		2006	2005
COMMON STOCK EQUITY			
Common stock, $2.50 par value; authorized 50,000,000 shares; outstanding 2006–29,098,173; 2005–28,183,032		$ 72,745	$ 70,457
Premium on common stock		253,167	223,382
Accumulated other comprehensive income/(loss), net of tax		93,637	(59,871)
Treasury stock at cost and other; shares 2006–1,473,023; 2005–636,895		(65,194)	(24,840)
Retained earnings		267,307	228,924
Total Common stock equity		621,662	438,052
LONG-TERM DEBT			
New Jersey Natural Gas			
First mortgage bonds:	*Maturity date*		
5.38% Series W	August 1, 2023	—	10,300
6.27% Series X	November 1, 2008	30,000	30,000
6.25% Series Y	August 1, 2024	—	10,500
Variable Series AA	August 1, 2030	25,000	25,000
Variable Series BB	August 1, 2030	16,000	16,000
6.88% Series CC	October 1, 2010	20,000	20,000
Variable Series DD	September 1, 2027	13,500	13,500
Variable Series EE	January 1, 2028	9,545	9,545
Variable Series FF	January 1, 2028	15,000	15,000
Variable Series GG	April 1, 2033	18,000	18,000
5% Series HH	December 1, 2038	12,000	12,000
4.5% Series II	August 1, 2023	10,300	—
4.6% Series JJ	August 1, 2024	10,500	—
4.9% Series KK	October 1, 2040	15,000	—
4.77% Unsecured senior notes	March 15, 2014	60,000	60,000
Capital lease obligation–Buildings	June 1, 2021	27,701	28,290
Capital lease obligation–Meters	October 1, 2012	28,525	27,322
Less: Current maturities of long-term debt		(3,739)	(3,253)
Total New Jersey Natural Gas Long-term debt		307,332	292,204
New Jersey Resources			
3.75% Unsecured senior notes	March 15, 2009	25,000	25,000
Total Long-term debt		332,332	317,204
Total Capitalization		$ 953,994	$ 755,256

See Notes to Consolidated Financial Statements

1. 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

CONSOLIDATED STATEMENTS OF COMMON STOCK EQUITY AND COMPREHENSIVE INCOME

(Thousands)	*Number of Shares*	Common Stock	Premium on Common Stock	Accumulated Other Comprehensive Income/(Loss)	Treasury Stock and Other	Retained Earnings	Total
Balance at September 30, 2003	27,233	$ 69,314	$ 208,749	$ 2,553	$ (16,042)	$ 154,367	$ 418,941
Net income						71,574	71,574
Other comprehensive income (loss),							
Unrealized gain on equity investments, net of tax of $(544)				787			787
Net unrealized loss on derivatives, net of tax of $4,663				(6,438)			(6,438)
Minimum pension liability adjustment, net of tax of $(392)				718			718
Other comprehensive (loss)							(4,933)
Comprehensive income							66,641
Common stock issued under stock plans	539	472	5,249		12,324		18,045
Tax benefits from stock plans			1,098				1,098
Cash dividend declared						(35,843)	(35,843)
Treasury stock and other	(31)				(965)		(965)
Balance at September 30, 2004	27,741	69,786	215,096	(2,380)	(4,683)	190,098	467,917
Net income						76,340	76,340
Other comprehensive income (loss)							
Unrealized gain on equity investments, net of tax of $(320)				463			463
Net unrealized loss on derivatives, net of tax of $40,063				(58,010)			(58,010)
Minimum pension liability adjustment, net of tax of $(39)				56			56
Other comprehensive (loss)							(57,491)
Comprehensive income							18,849
Common stock issued under stock plans	352	671	6,114		3,292		10,077
Tax benefits from stock plans			2,172				2,172
Cash dividend declared						(37,514)	(37,514)
Treasury stock and other	(547)				(23,449)		(23,449)
Balance at September 30, 2005	27,546	70,457	223,382	(59,871)	(24,840)	228,924	438,052
Net income						**78,519**	**78,519**
Other comprehensive income (loss)							
Unrealized gain on equity investments, net of tax of $(184)				**267**			**267**
Net unrealized gain on derivatives, net of tax of $(97,413)				**143,048**			**143,048**
Minimum pension liability adjustment, net of tax of $(7,113)				**10,193**			**10,193**
Other comprehensive income							**153,508**
Comprehensive income							**232,027**
Common stock issued under stock plans	**1,074**	**2,288**	**22,994**		**6,277**		**31,559**
Tax benefits from stock plans			**6,791**				**6,791**
Cash dividend declared						**(40,136)**	**(40,136)**
Treasury stock and other	**(995)**				**(46,631)**		**(46,631)**
Balance at September 30, 2006	**27,625**	**$ 72,745**	**$ 253,167**	**$ 93,637**	**$ (65,194)**	**$ 267,307**	**$ 621,662**

See Notes to Consolidated Financial Statements

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of the business

New Jersey Resources Corporation (NJR or the Company) has two principal subsidiaries and operates three business segments. New Jersey Natural Gas (NJNG), the Company's principal utility subsidiary, is a public utility which provides natural gas utility service to approximately 471,000 retail customers in central and northern New Jersey and comprises the Natural Gas Distribution segment. NJNG is subject to rate regulation by the New Jersey Board of Public Utilities (BPU).

NJR Energy Services (NJRES) is the Company's principal non-utility subsidiary that maintains and trades a portfolio of natural gas storage and transportation positions and provides wholesale energy and energy management services to customers from states in the Gulf Coast and Mid-Continent to New England and Canada. NJRES comprises the Energy Services segment.

Other subsidiaries of the Company include NJR Home Services (NJRHS), which provides services and installation of heating, ventilation and cooling (HVAC) systems throughout New Jersey; NJNR Pipeline (NJNR), which holds the Company's 5.53 percent interest in Iroquois Gas and Transmission System, L.P (Iroquois); NJR Energy, an investor in energy-related ventures; Commercial Realty and Resources (CR&R), which holds and develops commercial real estate; NJR Service, which provides shared administrative services; and NJR Investment, which makes energy-related equity investments, all of which comprise the Retail and Other segment.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Significant intercompany accounts and transactions have been eliminated.

Regulatory Assets & Liabilities

Under cost-based regulation, regulated utility enterprises generally are permitted to recover their operating expenses and earn a reasonable return on their utility investment.

NJNG maintains its accounts in accordance with the Uniform System of Accounts as prescribed by the BPU. In accordance with the ratemaking process, NJNG is required to follow Statement of Financial Accounting Standards (SFAS) No. 71, "*Accounting for the Effects of Certain Types of Regulation*" (SFAS 71), and as a result, the accounting principles applied by NJNG differ in certain respects from those applied by unregulated businesses.

Derivative Instruments

Derivative instruments associated with natural gas commodity contracts are recorded in accordance with SFAS No. 133, "*Accounting for Derivative Instruments and Hedging Activities*," as amended (SFAS 133), under which NJR records the fair value of derivatives held as assets and liabilities. NJR's unregulated subsidiaries record changes in the fair value of the effective portion of

derivatives qualifying as cash flow hedges, net of tax, in Accumulated other comprehensive loss, a component of total Common stock equity in the Consolidated Statements of Capitalization. Under SFAS 133, NJR also has certain derivative instruments that do not qualify as hedges. The change in fair value of these derivatives is recorded in Gas purchases on the Consolidated Statements of Income. In addition, the changes in the fair value of the ineffective portion of derivatives qualifying for hedge accounting are recorded as increases or decreases in natural gas costs or interest expense, as applicable, based on the nature of the derivatives.

Fair values of exchange-traded instruments, principally futures, swaps and certain options, are based on actively quoted market prices. Fair values are subject to change in the near term and reflect management's best estimate based on various factors. In establishing the fair value of commodity contracts that do not have quoted prices, such as physical contracts, over-the-counter options and swaps, management uses available market data and pricing models to estimate fair values. Estimating fair values of instruments that do not have quoted market prices requires management's judgment in determining amounts which could reasonably be expected to be received from, or paid to, a third party in settlement of the instruments. These amounts could be materially different from amounts that might be realized in an actual sale transaction.

See *Note 5. Financial Instruments and Risk Management* for additional details regarding natural gas trading and hedging activities.

NJNG's derivatives used to hedge its natural gas purchasing activities are recoverable through its Basic Gas Supply Service (BGSS), a component of its tariff. Accordingly, the offset to the change in fair value of these derivatives is recorded as a Regulatory asset or liability on the Consolidated Balance Sheets.

NJR has not designated any derivatives as fair value hedges as of September 30, 2006 and 2005.

Revenues

Revenues from the sale of natural gas to customers of NJNG are recognized in the period that gas is delivered and consumed by customers, including an estimate for unbilled revenue.

Unbilled revenues are associated solely with NJNG. Natural gas sales to individual customers are based on their meter readings, which are performed on a systematic basis throughout the month. At the end of each month, the amount of natural gas delivered to each customer after the last meter reading is estimated and NJNG recognizes unbilled revenues related to these amounts. The unbilled revenue estimates are based on monthly send-out amounts, estimated customer usage by customer type, weather effects, unaccounted-for gas and the most recent rates.

Generally, NJRES' commodity contracts fall within the "normal purchase normal sale" scope exception of SFAS 133 or are designated as a hedge for accounting purposes. The normal purchase normal sale scope exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that are designated as normal purchases and normal sales are accounted for under accrual accounting and, therefore, are not recorded on the balance sheet at fair value. For certain transactions that are designed to hedge the cash flows of a forecasted transaction, the effective portion of the hedge is

recorded in Accumulated other comprehensive income, a component of Common stock equity on the Consolidated Statements of Capitalization, and subsequently reclassified into earnings when the forecasted transaction is completed or settled. Any ineffective portion of the hedge is immediately reflected in earnings. Any commodity contract that does not meet the normal purchase normal sale exception, or does not qualify as a hedge, is recorded at its fair value as a component of operating revenues.

NJRES revenues from the sale of energy management services are a combination of a base service fee and incentive-based arrangements and are recognized as the services are performed and as the incentives are realized over the term of the agreement.

Revenues from all other activities are recorded in the period during which products or services are delivered and accepted by customers, or over the related contractual term.

Gas Purchases

NJNG's tariff includes a component for BGSS, which is normally revised on an annual basis. Under the BGSS, NJNG projects its cost of natural gas, net of supplier refunds, the impact of hedging activities and credits from nonfirm sales and transportation activities, and recovers or refunds the difference, if any, of such projected costs compared with those included in prices through levelized charges to customers. Any underrecoveries or overrecoveries are deferred and, subject to BPU approval, reflected in the BGSS in subsequent years.

NJRES gas purchases represent the total commodity contract cost, recognized upon completion of the transaction, for the commodity contracts that are either designated as a hedge for accounting purposes or qualify for the normal purchase normal sale scope exception under SFAS 133.

Income Taxes

The Company computes income taxes using the liability method, whereby deferred income taxes are generally determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. Net deferred tax assets are recorded when it is more likely than not such tax benefits will be realized. *See Note 9. Income Taxes*.

Investment tax credits have been deferred and are being amortized as a reduction to the tax provision over the average lives of the related properties.

Capitalized and Deferred Interest

The Company's capitalized interest totaled $1.1 million in fiscal 2006, $594,000 in fiscal 2005 and $660,000 in fiscal 2004 with average interest rates of 4.7 percent, 2.6 percent and 1.9 percent, respectively. These amounts are included in Utility plant and Real estate properties on the Consolidated Balance Sheets and are reflected on the Consolidated Statements of Income as a reduction to Interest charges, net. NJNG does not capitalize a cost of equity for its utility plant construction activities.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Pursuant to a BPU order, NJNG is permitted to recover carrying costs on uncollected balances related to underrecovered natural gas costs incurred through October 31, 2001, and its manufactured gas plant (MGP) remediation expenditure. See *Note 4. Regulation* . Accordingly, Other income included $2.3 million, $1.8 million and $4 million of interest related to underrecovered gas costs and MGP remediation in fiscal 2006, 2005 and 2004, respectively.

Sales Tax Accounting

Sales tax and Transitional Energy Facilities Assessment (TEFA) are collected from customers and presented in both operating revenues and operating expenses on the Consolidated Statements of Income as follows:

	September 30,		
(Thousands)	**2006**	2005	2004
Sales Tax	**$ 45,300**	$ 42,200	$ 36,600
TEFA	**8,100**	8,900	9,000
Total	**$ 53,400**	$ 51,100	$ 45,600

Statements of Cash Flows

For purposes of reporting cash flows, all temporary investments with maturities of three months or less are considered cash equivalents.

Utility Plant and Depreciation

Regulated property, plant and equipment is stated at original cost. Costs include direct labor, materials and third-party construction contractor costs, allowance for capitalized interest and certain indirect costs related to equipment and employees engaged in construction. Upon retirement, the cost of depreciable regulated property, plus removal costs less salvage, is charged to accumulated depreciation with no gain or loss recorded.

Depreciation is computed on a straight-line basis for financial statement purposes, using rates based on the estimated average lives of the various classes of depreciable property. The composite rate of depreciation was 3.03 percent of average depreciable property in fiscal 2006, 3.04 percent in fiscal 2005 and 3.06 percent in fiscal 2004. Property classifications and estimated useful lives, as of September 30, 2006 and 2005, are as follows:

Property Classifications	**Estimated Useful Lives**
Distribution Facilities	31 to 63 years
Transmission Facilities	42 to 62 years
Storage Facilities	36 to 47 years
All other property	5 to 35 years

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Impairment of Long-Lived Assets

The Company reviews the carrying amount of an asset for possible impairment whenever events or changes in circumstances indicate that such amount may not be recoverable. As part of a change in strategy related to CR&R, included in its Retail and Other segment, the Company determined in fiscal 2005 that 52 acres of undeveloped land located in Atlantic County, New Jersey, will no longer be developed by CR&R, but will be sold as undeveloped land. As a result, the Company estimated the fair value of the land and compared that with its carrying value. Accordingly, the Company recognized a pretax impairment charge of $3.9 million in fiscal 2005, which is included in Operation and Maintenance expense on the Consolidated Statements of Income. The net book value of the undeveloped land is included in Property, Plant & Equipment, net, on the Consolidated Balance Sheets. For the years ended September 30, 2006, 2005 and 2004, no other circumstances indicating impairment were identified.

Available for Sale Securities

Included in Other assets on the Consolidated Balance Sheets are certain investments in equity securities that have a fair value of $3.8 million and $3.6 million as of September 30, 2006 and 2005, respectively. Unrealized gains associated with these equity securities, which are included as a part of Accumulated other comprehensive income (loss), a component of Common stock equity, were approximately $172,000 and $742,000 for the fiscal years ended September 30, 2006 and 2005, respectively.

Equity in Earnings

Included in Other income on the Consolidated Statements of Income for the periods ending September 30, 2006, 2005 and 2004, respectively, are $2.0 million, $1.7 million and $1.2 million, respectively, of equity in pre-tax earnings, associated with NJNR's investment in Iroquois. Iroquois is a Delaware limited partnership, which owns and operates a 412-mile interstate natural gas transmission pipeline providing service to local gas distribution companies, electric utilities and electric power generators, as well as marketers and other end-users, directly or indirectly, by connecting with pipelines and interconnects throughout the northeastern United States. NJNR records its investment in Iroquois using the equity method.

Included in Income tax expense on the Consolidated Income Statement for the periods ending September 30, 2006, 2005 and 2004, are approximately $854,000, $706,000 and $502,000, respectively, of income taxes related to the equity in earnings from Iroquois.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Fair Value of Assets and Liabilities

The fair value of cash and temporary investments, accounts receivable, accounts payable, commercial paper and borrowings under revolving credit facilities is estimated to equal their carrying amounts due to the short maturity of those instruments. The estimated fair value of long-term debt excluding current maturities and capital lease obligations, is based on quoted market prices for similar issues and is as follows:

	September 30,	
(Thousands)	**2006**	2005
Carrying value	**$ 279,800**	$ 264,800
Fair market value	**$ 281,800**	$ 266,800

Pension and Postemployment Plans

NJR has two noncontributory defined pension plans covering substantially all employees, including officers. Benefits are based on each employee's years of service and compensation. NJR's funding policy is to contribute annually to these plans at least the minimum amount required under the Employee Retirement Income Security Act (ERISA) of 1974 and not more than can be deducted for federal income tax purposes. Plan assets consist of equity securities, fixed-income securities and short-term investments. NJR contributed $10 million and $10.9 million in aggregate to the plans in fiscal 2006 and 2005, respectively. NJR did not make a contribution to the plans in fiscal 2004.

NJR also provides two primarily noncontributory medical and life insurance plans for eligible retirees and dependents. Medical benefits, which make up the largest component of the plans, are based upon an age and years-of-service vesting schedule and other plan provisions. Funding of these benefits is made primarily into Voluntary Employee Beneficiary Association trust funds. NJR contributed $3.7 million, $638,000 and $12.6 million in aggregate to these plans in fiscal 2006, 2005 and 2004, respectively.

New Accounting Standards

In July 2006, the Financial Accounting Standards Board (FASB) issued Interpretation No. 48, "*Accounting for Uncertainty in Income Taxes*" (FIN 48), which alters the framework for recognizing income tax contingencies. Previously, under SFAS No. 5, "*Accounting for Contingencies*," the focus was on the subsequent liability recognition for estimated losses from tax contingencies where such losses were probable and the related amounts could be reasonably estimated. Under this new interpretation, a contingent tax asset (i.e., an uncertain tax position) may only be recognized if it is more likely than not that it will ultimately be sustained upon audit. The Company will adopt FIN 48 by the commencement of fiscal 2008. The Company is evaluating its tax positions for all jurisdictions and all years for which the statute of limitations remains open, as well as evaluating the impact that the adoption will have on its financial statements.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements" (SFAS 157). SFAS 157 defines fair value as the amount that would be exchanged to sell an asset or transfer a liability, in an orderly transaction between market participants, and establishes a fair value hierarchy of quotes and unobservable data that should be used to develop pricing assumptions. In addition, for

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

assets and liabilities that are not actively traded, for example, certain kinds of derivatives, SFAS 157 requires that a fair value measurement include an adjustment for risks inherent in a valuation technique and/or inputs, such as those used in pricing models. SFAS 157 is effective for fiscal years beginning after November 15, 2007, however, early adoption is permitted. The Company will adopt the provisions of the statement prospectively and is evaluating the adoption date and its effect on its financial condition.

In September 2006, the FASB issued SFAS No. 158, " *Employers' Accounting for Defined Benefit Pension and Other Postemployment Plans* " (SFAS 158). The statement requires an employer to recognize the funded status, measured as the difference between the fair value of plan assets and the projected benefit obligation, of its benefit plans. SFAS 158 does not change how pensions and other postemployment benefits are accounted for and reported in the income statement. Certain economic events, which previously required disclosure only in the notes to the financial statements, will be recognized as assets and liabilities and offset in Accumulated other comprehensive income, net of tax, on the Statement of Common Stock Equity to the extent such amounts are not recognized in earnings as part of net periodic benefit costs. Amounts recognized in Accumulated other comprehensive income are adjusted as they are subsequently recognized in earnings. The Company will adopt SFAS 158 on September 30, 2007 and will apply the provisions of the statement prospectively. The Company is currently evaluating the effect of adoption on its financial condition.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles (GAAP) used in the United States of America requires NJR to make estimates that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosure of contingencies during the reporting period. On a continuous basis, NJR evaluates its estimates, including those related to the calculation of the fair value of natural gas commodity contracts and derivative instruments, unbilled revenues, provisions for depreciation and amortization, regulatory assets and liabilities, income taxes, pensions and other postemployment benefits and contingencies related to environmental matters and litigation. NJR bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. In the normal course of business estimated amounts are subsequently adjusted to actual results that may differ from estimates.

Reclassification

Subsequent to the issuance of the September 30, 2005 Annual Report on Form 10-K, the Company determined that certain of its assets associated with broker margin accounts were incorrectly presented net as part of the Broker margin account in the Current Liabilities section of the Consolidated Balance Sheet as of September 30, 2005. The Company's management has concluded that this error was not material to the Consolidated Financial Statements, taken as a whole, and accordingly the September 30, 2005 balance sheet has been corrected by reclassifying the broker margin asset amount of $120.4 million as Broker margin account in the Current Assets section of the Consolidated Balance Sheet as of September 30, 2005. The September 30, 2005 Asset information included in *Note 10. Business Segment Data* has also been corrected to reflect this reclassification. This immaterial error had no effect on fiscal 2005 net income or cash flows.

2. LONG-TERM DEBT, DIVIDENDS AND RETAINED EARNINGS RESTRICTIONS

Annual long-term debt, excluding capital leases, redemption requirements are as follows (in millions):

September 30,	Redemption
2007	$ —
2008	—
2009	55.0
2010	—
2011	20.0
Thereafter	$ 204.8

NJNG First Mortgage Bonds

NJNG's mortgage secures its First Mortgage Bonds and represents a lien on substantially all of its property, including natural gas supply contracts. Certain indentures supplemental to the mortgage include restrictions as to cash dividends and other distributions on NJNG's common stock that apply as long as certain series of First Mortgage Bonds are outstanding. Under the most restrictive provision, approximately $176 million of NJNG's retained earnings were available for such purposes at September 30, 2006.

On October 1, 2004, NJNG's $25 million, 8.25% Series Z First Mortgage Bonds matured.

NJNG enters into loan agreements with the New Jersey Economic Development Authority (the EDA) under which the EDA issues tax-exempt bonds and the proceeds are loaned to NJNG. To secure its loans from the EDA, NJNG issues First Mortgage Bonds to the EDA with interest rates and maturity dates identical to those of the EDA Bonds.

In October 2005, NJNG entered into a loan agreement under which the EDA loaned NJNG the proceeds from $35.8 million of tax-exempt EDA Bonds consisting of $10.3 million, 4.5% (Series 2005A) and $10.5 million, 4.6% (Series 2005B) Revenue Refunding Bonds; and $15 million, 4.9% (Series 2005C) Natural Gas Facilities Revenue Bonds. The Series 2005 C bonds are supported by NJNG's 4.9% Series KK bonds with a maturity date of October 1, 2040.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

NJNG used the proceeds from the Series A and B bonds to refinance NJNG's $10.3 million, 5.38% Series W First Mortgage Bonds and its $10.5 million, 6.25% Series Y First Mortgage Bonds, respectively. The proceeds from the Series 2005C bonds were deposited into a construction fund. NJNG drew down $2.5 million from the construction fund in October 2005 and $4 million in September 2006.

At September 30, 2006 and 2005, NJNG had total long-term variable-rate debt outstanding of $97.1 million. At September 30, 2006 and 2005, the weighted average interest rate on NJNG's variable rate EDA Bonds was 3.3 percent and 2.2 percent, respectively.

In July 2006, NJNG purchased interest rate caps with several banks to hedge the interest rate exposure on its $97.1 million of tax-exempt, variable rate long-term debt with various maturity dates ranging from 2027 to 2040. The interest rate caps expire in July 2009 and limit NJNG's variable rate debt exposure for the tax-exempt EDA Bonds at 4.5 percent. The interest rate caps are treated as cash flow hedges, with changes in fair value accounted for in Accumulated other comprehensive income.

NJNG Unsecured Senior Notes

In March 2004, NJNG issued $60 million of Unsecured Senior Notes with a 10-year maturity and an interest rate of 4.77 percent. The proceeds of the Unsecured Senior Notes were used to reduce short-term debt of NJNG.

NJNG Sale-Leasebacks

Under an agreement entered into with a financing company in 2002, NJNG has received $4.1 million, $4.9 million and $3.9 million in fiscal 2006, 2005 and 2004, respectively, related to the sale-leaseback of a portion of its meters. NJNG plans to continue the sale-leaseback meter program on an annual basis.

1 f 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

In December 1995, the BPU approved NJNG's petition to enter into a master lease agreement for its headquarters building for a 25.5-year term with two 5-year renewal options. The present value of the agreement's minimum lease payments is reflected as both a capital lease asset and a capital lease obligation, which are included in Utility plant and Long-term debt, respectively, on the Consolidated Balance Sheets. In accordance with its ratemaking treatment, NJNG records rent expense as if the lease was an operating lease.

Minimum annual lease payments, under both sale-leasebacks for the meters and the building, as of the fiscal year end are as follows (in millions):

Fiscal Year Ended September 30,	Minimum Lease Payment
2007	$ 3.7
2008	4.0
2009	4.2
2010	4.6
2011	8.7
Thereafter	$ 31.0

NJR

NJR had no long-term variable-rate debt outstanding at September 30, 2006 and 2005.

In March 2004, NJR issued $25 million of Unsecured Senior Notes with a 5-year maturity and an interest rate of 3.75 percent. The r eds of the Unsecured Senior Notes were used to reduce short-term debt of NJR.

3. SHORT-TERM DEBT AND CREDIT FACILITIES

A summary of NJR's and NJNG's committed credit facilities, which require commitment fees on the unused amounts, are as follows:

	September 30,	
(Thousands)	**2006**	2005
NJR		
Bank credit facilities	**$ 325,000**	$ 295,000
Amount outstanding at year-end		
Notes payable to banks	**$ 129,200**	$ 174,100
Weighted average interest rate at year-end		
Notes payable to banks	**6.0 %**	4.8 %
NJNG		
Bank credit facilities	**$ 250,000**	$ 225,000
Amount outstanding at year-end		
Commercial paper	**$ 151,500**	—
Weighted average interest rate at year-end		
Commercial paper	**4.7 %**	—

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

NJR

In December 2004, NJR entered into a $275 million committed credit facility with several banks, with a 3-year term, expiring in December 2007. In November 2005, NJR amended the facility to increase it to $325 million.

In October 2006, NJRES entered into a 3-year $30 million committed credit facility with a multinational financial institution. Borrowings under this facility are guaranteed by NJR.

These facilities provide liquidity to meet the working capital and external debt-financing requirements of NJR and its nonregulated companies. Neither NJNG nor the results of its operations are obligated or pledged to support the NJR or NJRES facilities.

As of September 30, 2006, NJR had a $4.0 million letter of credit outstanding on behalf of NJRES, which will expire on August 1, 2007, in conjunction with a long-term natural gas storage agreement.

At September 30, 2006, NJR had a $675,000 letter of credit outstanding on behalf of CR&R, which will expire on December 3, 2007, in conjunction with development activities.These letters of credit reduce the amount available under NJR's committed credit facility by the same amount. NJR does not anticipate that these letters of credit will be drawn upon by the counterparties and they will be renewed as necessary.

NJNG

In December 2004, NJNG entered into a $225 million committed facility with several banks, with a 5-year term expiring in December 2009, which replaced a $225 million credit facility with a shorter term. In November 2005, NJNG amended this facility to increase it to $250 million. This facility is used to support NJNG's commercial paper program.

As of September 30, 2006, NJNG had a $45 million letter of credit outstanding that will expire on December 31, 2006, in conjunction with a long-term swap agreement. The long-term swap agreement was entered into as a hedge related to an offsetting physical purchase of natural gas for the same time period and volume. This letter of credit reduces the amount available under NJNG's committed credit facility by the same amount. NJNG does not anticipate that this letter of credit will be drawn upon by the counterparty and it will be renewed as necessary, upon its expiration.

4. REGULATION

Energy Deregulation Legislation

In February 1999, the Electric Discount and Energy Competition Act (EDECA), which provided the framework for the restructuring of New Jersey's energy market, became law. In March 2001, the BPU issued a written order that approved a stipulation among various parties to fully open NJNG's residential markets to competition, restructure its prices and expand an incentive for residential and small commercial customers to switch to transportation service. As required by EDECA, NJNG restructured its prices to segregate its BGSS, the component of prices whereby NJNG provides the commodity and interstate pipeline capacity to the customer, and delivery (i.e., transportation) prices. NJNG earns no utility gross margin on the commodity portion of its natural gas sales. NJNG earns utility gross margin through the delivery of natural gas to its customers. Customers can choose the supplier of their natural gas commodity.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Under EDECA, the BPU is required to audit the state's energy utilities every two years. The primary purpose of the audit is to ensure that utilities and their affiliates offering unregulated retail services do not have any unfair competitive advantage over nonaffiliated providers of similar retail services. A combined competitive services and management audit of NJNG began in November 2006.

Weather and Usage

For the reporting periods through September 30, 2006, the impact of weather on NJNG's utility gross margin had been significantly mitigated due to its Weather Normalization Clause (WNC), however, lower customer usage per degree-day was not captured by the WNC. NJNG has experienced lower customer usage per degree-day, which it believes is due primarily to customer conservation resulting from an increase in wholesale commodity costs. In order to reduce the impact of the reduction in customer usage, NJNG filed a Conservation and Usage Adjustment (CUA) proposal with the BPU in December 2005. On October 12, 2006, the BPU approved a stipulation reached with the staff of the BPU and the Division of Rate Counsel (on September 30, 2006) that modified the CUA proposal into the Conservation Incentive Program (CIP).

The CIP is a three year pilot program, designed to decouple the link between customer usage and NJNG's utility gross margin to allow NJNG to encourage its customers to conserve energy. For the term of the pilot the existing WNC will be suspended and replaced with the CIP tracking mechanism which addresses utility gross margin variations related to both weather and customer usage in comparison to established benchmarks. Recovery of such utility gross margin variations is subject to additional conditions including an earnings test and an evaluation of BGSS-related savings under the CIP agreement. If NJNG does not file for a rate review with the BPU within two years, the return on equity for the earnings test will decline from 10.5 percent to 10.25 percent. To encourage energy efficiency, NJNG is obligated to initiate and fund programs to further customer conservation efforts over the term of the pilot. In September 2006, NJNG accrued the estimated present value of this obligation, which was approximately $1.8 million. An annual filing for the clause shall be made in June of each year coincident with NJNG's annual BGSS filing.

Basic Gas Supply Service

On January 6, 2003, the BPU approved a statewide BGSS agreement requiring all New Jersey natural gas utilities to make an annual filing by each subsequent June 1 for review of BGSS and to request a potential rate change to be effective the following October 1. The agreement also allows natural gas utilities to provisionally increase residential and small commercial customer BGSS rates up to 5 percent on December 1 and February 1 on a self-implementing basis, after proper notice and BPU action on the June filing. Such increases are subject to subsequent BPU review and final approval.

On June 1, 2005, NJNG filed for a 4.2 percent price increase to an average residential customer, to be effective on October 1, 2005. On July 21, 2005, NJNG amended its filing, requesting an effective date of September 1, 2005 . The BPU approved this increase on a provisional basis on August 19, 2005, and it became effective on September 1, 2005 . This requested increase was necessary due to higher wholesale commodity costs and was subject to refund with interest.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

On November 10, 2005, NJNG filed for a 23.2 percent price increase to an average residential customer, which was provisionally approved and became effective on December 14, 2005. This increase was necessary due to higher wholesale commodity costs and was subject to refund with interest.

In January and March 2006, NJNG filed supporting documentation with the BPU for a bill credit to its customers for the period February 1, 2006 through April 30, 2006. The bill credits, which temporarily reduced the BGSS tariff component, provided a benefit of approximately $28.6 million to NJNG's residential and small commercial customers during that period.

On June 1, 2006, NJNG filed for a reduction to the BGSS rate that would decrease an average residential customer's bill by approximately 6.6 percent. The BPU approved this decrease on a provisional basis on September 27, 2006. NJNG refunded approximately $22.5 million to residential and small commercial customers in September 2006.

All of the above credits and refunds were possible due primarily to a decline in wholesale natural gas prices that occurred subsequent to NJNG's November 10, 2005 BGSS filing. These refunds and credits apply only to NJNG's residential and small commerical sales customers, as transportation customers are not subject to the BGSS clause

On October 25, 2006, NJNG filed supporting documentation with the BPU for a self-implementing BGSS price reduction to be effective November 1, 2006, which will lower residential and small commercial customers' bills by approximately an additional 4 percent. This decrease was due to the continued reduction in the wholesale cost of natural gas.

Incentive Programs

NJNG is eligible to receive incentives for reducing BGSS costs through a series of utility gross margin-sharing programs that include off-system sales, capacity release, storage incentive and financial risk management programs. On April 12, 2006, the BPU approved an agreement whereby the existing utility gross margin-sharing programs between customers and shareowners were extended through October 31, 2007.

al Benefits Clause (SBC)

The SBC is comprised of three primary components, a Universal Service Fund rider (USF), a Manufactured Gas Plant Remediation Adjustment Clause (RAC), and the New Jersey Clean Energy Program (NJCEP). The USF is a permanent statewide program that was approved by the BPU in March 2003 for all natural gas and electric utilities for the benefit of limited-income customers; the RAC is a rider approved by the BPU in June 1992 that provides for recovery of expenditures incurred to remediate former gas manufacturing facilities; and the NJCEP is a program approved by the BPU in March 2001 designed to promote energy efficiency and renewable energy. Recovery of SBC program costs is subject to BPU approval of annual filings that include an updated report of expenditures incurred each year.

Universal Service Fund

Through the USF, eligible customers receive a credit toward their utility bill. The credits applied to eligible customers are recovered through the USF rider in the SBC. NJNG recovers carrying costs on

deferred USF balances. On July 1, 2006, the natural gas utilities filed to increase the statewide USF recovery rate as a result of higher USF benefits effective October 1, 2006 . In October 2006, the BPU approved the requested recovery rate to be effective November 1, 2006, which results in an approximate .9 percent increase to the total bill of a residential sales customer.

Clean Energy Program

On December 23, 2004, the BPU issued a decision establishing the statewide NJCEP funding amount for the period from January 1, 2005 to December 31, 2008. NJNG's obligation to the state of New Jersey, which is recoverable from customers through the SBC, gradually increases from $4.2 million in fiscal 2005 to $9.5 million in fiscal 2008. As a result, NJNG has a remaining discounted liability of $19.6 million and a corresponding Regulatory asset included in SBC at September 30, 2006. Additionally, this decision reaffirmed the right and basis for utilities to collect lost revenue related to the implementation of Clean Energy programs for measures installed prior to December 31, 2003. As of September 30, 2005, NJNG recorded $1 million of revenue related to this program and has sought recovery of such revenue in its September 30, 2005 SBC filing. NJNG also filed the results of the fiscal 2005 WNC on September 30, 2005, which seeks to apply a $2.1 million refund to other clauses that are currently underrecovered. The October 25, 2006 filing modifies this request and primarily seeks to apply the WNC refund to the 2005-2006 winter period WNC margin deficiency.

Remediation Adjustment Clause

On April 12, 2006, the BPU approved NJNG's 2004 annual filing and signed a stipulation agreement that maintained the existing recovery rate of approximately $19.2 million annually, which recognizes remediation expenditures through June 30, 2004.

October 2006 Filings

On October 25, 2006, NJNG made its annual SBC filing, which updates RAC expenditures through June 30, 2006, and provides current energy funding projections. In addition, NJNG proposed to reduce the RAC recovery from $19.2 million to $15.9 million, annually, and increase the recovery for NJCEP from $7.1 million to $13.6 million, for the calendar year 2007, to address current funding obligations and a prior year underrecovery. At the same time, NJNG filed supporting documentation for the WNC surcharge of approximately $10.3 million for the period from October 1, 2005 through May 31, 2006. The combined effect of these two filings is an increase of approximately 1.7 percent for the average residential customer, with a requested effective date of January 1, 2007.

Other Proceedings

NJNG is also involved in various proceedings associated with several other adjustment clauses and an audit of its BGSS, the outcome of which, in management's opinion, will not have a material adverse impact on its financial condition, results of operations or cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Regulatory Assets & Liabilities

At September 30, 2006 and 2005, respectively, the Company had the following regulatory assets, all related to NJNG, on the Consolidated Balance Sheets:

(Thousands)	2006	2005	Recovery Period
Regulatory assets–current			
Underrecovered gas costs	$ —	$ 37,049	Less than one year *(1)*
WNC	8,105	(2,145)	Less than one year *(4)*
Total-current	$ 8,105	$ 34,904	
Regulatory assets–noncurrent			
Remediation costs (Note 13)			
Expended, net	$ 83,746	$ 86,912	*(2)*
Liability for future expenditures	105,400	93,920	*(3)*
Deferred income and other taxes	13,476	12,901	Various
Derivatives (Note 1)	82,451	—	Through Oct. 2011 *(5)*
Postemployment benefit costs (Note 11)	2,117	2,418	Through Sept. 2014 *(4)*
SBC	35,796	35,215	Various *(6)*
Total-noncurrent	$ 322,986	$ 231,366	

(1) Recoverable, subject to BPU annual approval, without interest, except for $6.4 million that was recoverable with interest through November 30, 2005.

(2) Recoverable, subject to BPU approval, with interest over rolling seven-year periods. Also net of estimated future insurance proceeds of $10 million at September 30, 2006.

(3) Estimated future expenditures. Recovery will be requested when actual expenditures are incurred. (See Note 13. Commitments and Contingent Liabilities.)

(Recoverable/refundable, subject to BPU approval, without interest.

(. Recoverable, subject to BPU approval, through BGSS, without interest.

(6) Recoverable with interest, subject to BPU approval.

If there are any changes in regulatory positions that indicate the recovery of regulatory assets is not probable, the related cost would be charged to income in the period of such determination.

At September 30, 2006 and 2005, the Company had the following regulatory liabilities, all related to NJNG, on the Consolidated Balance Sheets:

(Thousands)	2006	2005
Regulatory liability–current		
Overrecovered gas costs	$ 1,710	$ —
Regulatory liabilities–noncurrent		
Cost of removal obligation (1)	$ 58,161	$ 77,067
Market development fund (MDF) (2)	6,059	5,945
Derivatives	—	35,135
Total-noncurrent	$ 64,220	$ 118,147

(1) NJNG accrues and collects for cost of removal in rates. This liability represents collections in excess of actual expenditures. Approximately $18.2 million of regulatory assets relating to asset retirement obligation have been netted against the cost of removal obligation as of September 30, 2006. See Note 8. Asset Retirement Obligations

(2) The MDF, created with funds available as a result of the implementation of the Energy Tax Reform Act of 1997, currently provides financial incentives to encourage customers to switch to third party suppliers and has supported other unbundling related initiatives. Balance earns interest at prevailing SBC rate. The MDF funding obligations terminated as of October 31, 2006. $4.9 million of this fund was credited to the New Jersey Clean Energy Program, as a result of a filing with the BPU on October 25, 2006. The remaining balance is being held until final resolution of NJNG's fiscal 2005 SBC filing.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

5. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company and its subsidiaries are subject to market risk due to fluctuations in the price of natural gas. To hedge against such fluctuations, the Company and its subsidiaries enter into futures contracts, option agreements and swap agreements to hedge purchases and sales of natural gas.

Generally, all of the commodity contracts of NJRES meet the "normal purchase normal sale" scope exception of SFAS No. 133, and are accounted for under accrual accounting, or are designated as a hedge for accounting purposes. If these commodity contracts do not meet the normal purchase normal sale scope exception, or if they do not qualify as a hedge, they are recorded at fair value as a component of operating revenues.

The amounts included in Other comprehensive income related to natural gas instruments, which have been designated as cash flow hedges, will reduce or increase gas costs as the underlying physical transaction occurs and is settled. Based on the amount recorded in Accumulated other comprehensive income at September 30, 2006, $96.3 million is expected to be recorded as a decrease to gas costs in fiscal 2007.

In March 1992, NJR Energy entered into a long-term fixed-price contract to sell natural gas (Gas Sale Contract) to an energy marketing company, which expires in 2010. NJR Energy entered into a series of swap agreements and purchase contracts, which hedged its risk for sales volumes under the Gas Sale Contract that were in excess of the estimated production from natural gas reserves owned at the time. These cash flow hedges cover various periods of time ranging from November 2006 to October 2010.

The respective obligations of NJR Energy and the counterparties under the swap agreements are guaranteed, subject to a maximum amount, by the Company and the respective counterparties' parent corporations. In the event of nonperformance by the counterparties and their parent corporations, NJR Energy's financial results would be impacted by the difference, if any, between the fixed price it is receiving under the Gas Sale Contracts and the floating price that it is paying under the purchase contract. However, the Company does not anticipate nonperformance by the counterparties, which are major national energy companies.

The following table summarizes the ineffective portions of the Company's cash flow hedges that are included as a benefit (expense) as part of the Gas purchases in the Consolidated Statements of Income for the fiscal years ended September 30, 2006, 2005 and 2004:

(Thousands)	**2006**	2005	2004
NJRES	**$ 8,286**	$ (5,235)	$ (3,507)
NJR Energy	**57**	68	116
Total Consolidated	**$ 8,343**	$ (5,167)	$ (3,391)

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

The ineffective portions of the NJRES cash flow hedges relate to certain natural gas basis swap contracts, which concluded in October 2006, that were deemed ineffective in fiscal 2001 upon the adoption of SFAS 133.

Generally, exchange-traded futures contracts require a deposit of margin cash, the amount of which is subject to change based on market movements and in accordance with exchange rules. The Company maintains two broker margin accounts for NJNG and NJRES. The balances as of September 30, 2006 and 2005 are as follows:

(Thousands)	**2006**	2005
NJNG broker margin deposit (liability)	**$ 30,833**	$ (122,244)
NJRES broker margin (liability) deposit	**(14,220)**	120,420

6. STOCK BASED COMPENSATION

In December 2004, the FASB issued SFAS No. 123 (revised 2004) *"Share-Based Payment"* (SFAS 123R). This statement requires companies to record compensation expense for all share-based awards granted subsequent to the adoption of SFAS 123R. In addition, SFAS 123R requires the recording of compensation expense for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In October 2002, the Company adopted the prospective method of SFAS No. 123, *"Accounting for Stock-Based Compensation"* (SFAS 123), and as such has recognized compensation expense for grants issued subsequent to October 1, 2002 at the fair value of the options at date of grant. The Company determines the fair value of the options using the Black-Scholes method. The Company adopted SFAS 123R effective October 1, 2005, and the adoption did not have a material impact on its financial condition, results of operations or cash flows.

The following table summarizes all stock-based compensation expense recognized during the fiscal years ended September 30, 2006, 2005 and 2004 respectively:

(Thousands)	**2006**	2005	2004
Stock-based compensation expense:			
Stock options	**$ 430**	$ 328	$ 210
Performance units	**270**	(1,075)	577
Restricted stock	**21**	—	—
Compensation expense included in Operation and Maintenance expense	**721**	(747)	787
Income tax benefit	**(294)**	305	(322)
Total, net of tax	**$ 427**	$ (442)	$ 465

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

The following table presents the pro forma impacts on both net income and earnings per share for the fiscal years ended September 30, 2005 and 2004 for options granted prior to October 1, 2002, which were accounted for under Accounting Principles Board (APB) Opinion No. 25, "*Accounting for Stock Issued to Employees*." Beginning October 1, 2005, the cost of all options are expensed under SFAS 123R.

(Thousands)	2005	2004
Net income, as reported	$ 76,340	$ 71,574
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	194	125
Deduct: Total stock-based employee compensation expense determined under the fair value-based method for all awards, net of related tax effects	(404)	(668)
Pro forma net income	$ 76,130	$ 71,031

	2005	2004
Basic–earnings per share, as reported	$ 2.77	$ 2.60
Basic–earnings per share, pro forma	$ 2.76	$ 2.58
Diluted–earnings per share, as reported	$ 2.71	$ 2.55
Diluted–earnings per share, pro forma	$ 2.71	$ 2.53

Stock Options

The following table summarizes the assumptions used in the Black-Scholes option-pricing model and the resulting weighted average fair value of the stock options issued during the last three fiscal years:

	2006	2005	2004
Dividend yield	3.2 %	3.0 %	3.1 %
Volatility	13.2 %	12.7 %	14.3 %
Expected life (years)	7	7	7
Risk-free interest rate	4.6 %	4.3 %	3.9 %
Weighted average fair value	$ 5.44	$ 4.14	$ 5.64

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

The following table summarizes the stock option activity for the past three fiscal years:

	Shares	Weighted Average Exercise Price
Outstanding at September 30, 2003	1,799,729	$ 26.20
Granted	30,000	$ 38.75
Exercised	(140,048)	$ 20.28
Forfeited	(2,003)	$ 31.92
Outstanding at September 30, 2004	1,687,678	$ 26.90
Granted	177,500	$ 45.01
Exercised	(269,234)	$ 24.06
Forfeited	(50,287)	$ 32.17
Outstanding at September 30, 2005	1,545,657	$ 29.29
Granted	**28,200**	**$ 42.83**
Exercised	**(883,779)**	**$ 26.23**
Forfeited	**(18,247)**	**$ 36.69**
Outstanding at September 30, 2006	**671,831**	**$ 33.67**
Exercisable at September 30, 2006	**485,806**	**$ 30.53**
Exercisable at September 30, 2005	1,259,270	$ 26.88
Exercisable at September 30, 2004	1,132,184	$ 25.82

For the stock options listed above, there are $758,000 in costs related to unvested options that are expected to be recognized over the next 4 years.

The following table summarizes stock options outstanding and exercisable as of September 30, 2006:

	Outstanding				Exercisable		
Exercise Price Range	Number of Stock Options	Weighted Average Remaining Contractual Term (in years)	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)	Number of Stock Options	Weighted Average Exercise Price	Aggregate Intrinsic Value (in thousands)
$18.22 – $22.78	13,886	1.3	$ 21.60	$ 385	13,886	$ 21.60	$ 385
$22.78 – $27.33	96,890	3.1	$ 25.83	2,274	96,890	$ 25.83	2,274
$27.33 – $31.89	333,605	4.2	$ 29.64	6,559	295,605	$ 29.40	5,882
$31.89 – $36.44	10,500	6.5	$ 33.71	163	10,500	$ 33.71	163
$36.44 – $41.00	22,000	7.4	$ 38.09	246	14,000	$ 38.30	154
$41.00 – $45.55	194,950	8.5	$ 44.81	875	54,925	$ 44.59	259
Total	671,831	5.4	$ 33.67	$ 10,502	485,806	$ 30.53	$ 9,117

1 *i* 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Performance Units

The Company has issued performance units to various officers which are market conditions awards. The following table summarizes the Performance Unit activity under the Employee and Outside Director Long-Term Incentive Compensation Plan for the past three fiscal years:

	Units (1)	Weighted Average Grant Date Fair Value
Oustanding at September 30, 2003	83,950	$ 30.06
Granted	—	—
Vested	(14,475)	$ 27.33
Cancelled/forfeited	—	—
Non-vested and outstanding at September 30, 2004	69,475	$ 30.62
Granted	36,750	$ 45.55
Vested	(14,475)	$ 27.33
Cancelled/forfeited	(55,000)	$ 31.49
Non-vested and outstanding at September 30, 2005	36,750	$ 45.55
Granted	7,200	$ 42.80
Vested	—	—
Cancelled/forfeited	(2,250)	45.55
Non-vested and outstanding at September 30, 2006	**41,700**	**$ 45.08**

(*The number of common shares issued related to performance units may range form zero to 150 percent of the number of units shown in the table above based on the Company's achievement of performance goals associated with NJR total shareowner return relative to a selected peer group of companies.*

The Company measures compensation expense related to performance units based on the fair value of these awards at their date of grant. Compensation expense for performance units is recognized for awards that ultimately vest, and is not adjusted based on actual achievement of the performance goals. The Company estimated the fair value of the performance units on the date of grant using a Lattice model.

There are $479,000 in costs related to unvested performance units that are expected to be recognized over the next two years.

Restricted Stock

In fiscal 2006, the Company granted 2,755 shares of restricted stock pursuant to the Employee and Outside Director Long-Term Incentive Compensation Plan. The stock is restricted for a period of four years from grant date. The Company is recognizing expense based on the market value of the stock as of the grant date over the vesting period.

There are $103,000 in costs related to unvested restricted stock shares that are expected to be recognized over the next four years.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

7. EARNINGS PER SHARE (EPS)

The following table presents the calculation of the Company's basic and diluted EPS:

(Thousands)	2006	2005	2004
Net Income	**$ 78,519**	$ 76,340	$ 71,574
Basic EPS			
Average shares of common stock outstanding–basic	**27,862**	27,591	27,530
Basic earnings per common share	**$ 2.82**	$ 2.77	$ 2.60
Diluted EPS			
Average shares of common stock outstanding–basic	**27,862**	27,591	27,530
Incremental shares *(1)*	**219**	530	523
Average shares of common stock outstanding–diluted	**28,081**	28,121	28,053
Diluted earnings per common share	**$ 2.80**	$ 2.71	$ 2.55

(1) Incremental shares consist of stock options, stock awards and performance units

8. ASSET RETIREMENT OBLIGATIONS (ARO)

In March 2005, the FASB issued Financial Interpretation Number 47, *"Accounting for Conditional Asset Retirement Obligations"* (FIN 47), to clarify the term "conditional asset retirement obligation" (CARO) as used in SFAS No. 143, " *Accounting for Asset Retirement Obligations* ." A CARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the company. FIN 47 removes the conditionality surrounding an such that the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. NJR adopted FIN 47 effective as of September 30, 2006.

FIN 47 requires NJR to recognize a reasonably estimated liability for the fair value of a CARO. The fair value of a liability for a CARO should be recognized when incurred, which is generally upon acquisition, construction, development and/or through the normal operation of the asset. An asset retirement cost will be capitalized concurrently by increasing the carrying amount of the related asset by the same amount as the liability. In periods subsequent to the initial measurement, NJR is required to recognize changes in the liability resulting from the passage of time (accretion) or due to revisions to either timing or the amount of the originally estimated cash flows to settle the CARO.

As of September 30, 2006, NJR identified a CARO related to the costs associated with cutting and capping its main and service gas distribution pipelines of NJNG, which is required by New Jersey law when taking such gas distribution pipeline out of service.

NJNG recorded liabilities of approximately $5.1 million related to the present value of CARO and $18.2 million related to accumulated accretion. NJR believes that CARO-related amounts represent timing differences in the recognition of legal retirement costs that are currently being recovered in NJNG's rates and, therefore, is deferring such differences as a regulatory asset under SFAS 71. The $18.2 million related to accumulated accretion, which represents a regulatory asset, has been netted against NJNG's cost of removal regulatory liability on the Consolidated Balance Sheet.

1 i 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

The pro forma amounts of the liabilities for asset retirement obligations for the periods ended September 30, 2006, 2005, and 2004, respectively, are presented in the following table. These amounts were calculated using current information, assumptions and interest rates:

	Pro-Forma September 30,		
(Thousands)	2006	2005	2004
Beginning of period ARO liability	$ 22,029	$ 20,841	$ 19,725
Accretion (1)	1,264	1,188	1,116
End of period ARO liability	$ 23,293	$ 22,029	$ 20,841

(1) Accretion is not reflected on NJR's Consolidated Statements of Operations as it is deferred and recovered in rate base.

Accretion for the next five years, is estimated to be as follows:

(Thousands)	
Fiscal Year Ended September 30,	**Estimated Accretion**
2007	$ 1,312
2008	$ 1,384
2009	$ 1,459
2010	$ 1,538
2011	$ 1,618

Accretion amounts will not be reflected as expense on NJR's Consolidated Statements of Operations, but rather deferred as a regulatory asset and netted against NJNG's regulatory liabilities, for presentation purposes, on the Consolidated Balance Sheet.

9. INCOME TAXES

The Company's federal tax returns through fiscal 2002 either have been reviewed by survey, examined by the Internal Revenue Service (IRS), or the related statute of limitations has expired and all matters have been settled. As part of standard procedure in handling a fiscal 2003 federal income tax refund request, an IRS audit review of the fiscal 2003 and 2004 tax returns is under way.

1 i 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

A reconciliation of the U.S. federal statutory rate of 35 percent to our effective rate from operations for the fiscal years ended September 30, 2006, 2005 and 2004 is as follows:

(Thousands)	2006	2005	2004
Statutory income tax expense	**$ 44,987**	$ 43,839	$ 41,132
Change resulting from			
State income taxes	**7,909**	7,640	7,057
Change in tax rate	**(216)**	—	—
Depreciation and cost of removal	**(1,674)**	(1,641)	(1,441)
Investment tax credits	**(322)**	(322)	(322)
Other	**(662)**	(603)	(481)
Income tax provision	**$ 50,022**	$ 48,913	$ 45,945
Effective income tax rate	**38.9 %**	39.1 %	40.0 %

The Income tax provision (benefit) from operations consists of the following:

(Thousands)	2006	2005	2004
Current			
Federal	**$ 37,631**	$ 45,142	$ 22,560
State	**11,636**	14,327	8,547
Deferred			
Federal	**878**	(7,660)	12,850
State	**199**	(2,574)	2,310
Investment tax credits	**(322)**	(322)	(322)
Income tax provision	**$ 50,022**	$ 48,913	$ 45,945

For fiscal 2006 the statutory state income tax rate increased to 9.36 percent from the prior year state income tax rate of 9 percent. This increase is due to a 4 percent surtax which has been imposed by the state of New Jersey during fiscal 2006. The surtax is expected to expire June 30, 2009.

8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

The temporary differences, which give rise to deferred tax assets and liabilities, consist of the following:

(Thousands)	2006	2005
Current		
Underrecovered gas costs	$ (702)	$ 15,135
WNC	3,330	(876)
Conservation program	4,112	(3,338)
Other	(1,772)	(1,937)
Current deferred tax liability, net	$ 4,968	$ 8,984
Noncurrent		
Property-related items	$ 128,835	$ 131,170
Customer contributions	(1,421)	(2,304)
Capitalized overhead and interest	(2,677)	936
Unamortized investment tax credits	(4,219)	(4,392)
Remediation costs	30,919	32,434
Deferred service contract revenue	(2,317)	(2,411)
Deferred gain	(2,512)	(4,795)
Fair value of derivatives	63,220	(39,606)
Partnership	7,524	6,115
Other	9,748	(12,338)
Total non-current deferred tax liabilities, net	227,100	104,809
Total deferred tax liabilities, net	$ 232,068	$ 113,793

1 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

10. BUSINESS SEGMENT DATA

Information related to the Company's various business segments, excluding capital expenditures, which are presented in the Consolidated Statements of Cash Flows, is detailed below.

The Natural Gas Distribution segment consists of regulated energy and off-system, capacity and storage management operations. The Energy Services segment consists of unregulated wholesale energy operations. The Retail and Other segment consists of appliance and installation services, commercial real estate development, investments and other corporate activities.

(Thousands)	2006	2005	2004
Operating Revenues			
Natural Gas Distribution	$ 1,138,774	$ 1,138,280	$ 928,902
Energy Services	2,133,540	1,973,268	1,582,103
Retail and Other	27,568	36,900	22,698
Subtotal	3,299,882	3,148,448	2,533,703
Intersegment Revenues *(1)*	(274)	(186)	(96)
Total	$ 3,299,608	$ 3,148,262	$ 2,533,607
Depreciation and Amortization			
Natural Gas Distribution	$ 34,146	$ 32,905	$ 31,776
Energy Services	211	253	204
Retail and Other	396	517	469
Total	$ 34,753	$ 33,675	$ 32,449
Operating Income			
Natural Gas Distribution	$ 88,029	$ 97,502	$ 98,823
Energy Services	53,745	31,426	24,868
Retail and Other	4,689	9,440	3,527
Total	$ 146,463	$ 138,368	$ 127,218

The Company's assets for the various business segments are detailed below:

(Thousands)	2006	2005
Assets as of September 30,		
Natural Gas Distribution	$ 1,586,934	$ 1,581,758
Energy Services	714,867	621,471
Retail and Other	107,213	136,420
Intersegment Assets *(1)*	(10,086)	(9,401)
Total	$ 2,398,928	$ 2,330,248

(1) Consists of transactions between subsidiaries that are eliminated in consolidation.

11. EMPLOYEE BENEFIT PLANS

Pension and Other Postemployment Benefit Plans (OPEB)

The Company has two trusteed, noncontributory defined benefit retirement plans covering regular represented and nonrepresented employees with more than one year of service. All represented

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

employees of NJRHS hired on or after October 1, 2000, are covered by an enhanced defined contribution plan instead of the defined benefit plan.

Defined benefit plan benefits are based on years of service and average compensation during the highest 60 consecutive months of employment.

The Company provides postemployment medical and life insurance benefits to employees who meet the eligibility requirements.

The Company's funding policy for its pension plans is to contribute at least the minimum amount required by the Employment Retirement Income Security Act of 1974, as amended. In fiscal 2006 and 2005, the Company had no minimum funding requirements; however, the Company made discretionary contributions of $10 million and $10.9 million in fiscal 2006 and 2005, respectively, to the pension plans. The Company elected to make these discretionary tax-deductible contributions to improve the funded status of the pension plans. The Company currently has no plans to fund the pension plans over the next five years.

The Company made tax-deductible contributions of $3.7 million in fiscal 2006 and $638,000 in fiscal 2005 to the OPEB plans. It is anticipated that the Company's funding level to the OPEB plans will be approximately $600,000 annually over the next five years.

1 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

The components of the net periodic cost for pension benefits and OPEB costs (principally health care and life insurance) for employees and covered dependents were as follows:

	Pension			OPEB		
(Thousands)	**2006**	2005	2004	**2006**	2005	2004
Service cost	**$ 3,004**	$ 2,600	$ 2,479	**$ 1,582**	$ 1,297	$ 1,059
Interest cost	**5,633**	5,302	4,918	**2,472**	2,181	1,865
Expected return on plan assets	**(7,127)**	(6,404)	(6,574)	**(1,832)**	(1,700)	(857)
Recognized actuarial loss	**1,731**	1,045	634	**—**	682	456
Recognized net initial obligation	**(11)**	(113)	(113)	**357**	357	357
Prior service cost amortization	**84**	111	87	**78**	78	77
Special termination benefit	**—**	—	801	**834**	72	62
Net periodic cost	**$ 3,314**	$ 2,541	$ 2,232	**$ 3,491**	$ 2,967	$ 3,019
The weighted average assumptions are as follows:						
Discount rate	**6.00 %**	5.75 %	6.00 %	**6.00 %**	5.75 %	6.00 %
Expected asset return	**9.00 %**	9.00 %	9.00 %	**8.50 %**	8.50 %	8.50 %
Compensation increase	**3.75 %**	3.75 %	3.75 %	**3.75 %**	3.75 %	3.75 %
Initial health care cost trend rate (HCCTR)	**—**	—	—	**10.00 %**	9.00 %	9.50 %
Ultimate HCCTR	**—**	—	—	**5.00 %**	4.50 %	4.50 %
Year ultimate HCCTR reached	**—**	—	—	**2013**	2010	2010

	Pension			OPEB		
	2006	2005	2004	**2006**	2005	2004
Effect of a 1 percentage point increase in the HCCTR on:						
Year-end benefit obligation	**—**	—	—	**$ 8,096**	$ 7,523	$ 6,292
Total service and interest cost	**—**	—	—	**$ 921**	$ 734	$ 633
Effect of a 1 percentage point decrease in the HCCTR on:						
Year-end benefit obligation	**—**	—	—	**$ (6,489)**	$ (5,995)	$ (5,019)
Total service and interest costs	**—**	—	—	**$ (721)**	$ (520)	$ (490)

In selecting an assumed discount rate, NJR uses a modeling process that involves selecting a portfolio of high-quality corporate debt issuances (AA- or better) whose cash flows (via coupons or maturities) match the timing and amount of NJR's expected future benefit payments. NJR considers the results of this modeling process, as well as overall rates of return on high-quality corporate bonds and changes in such rates over time, in determination of its assumed discount rate.

NJR's general approach for determining the overall expected long-term rate of return on assets considers historical and expected future asset returns, the current and future targeted asset mix of the plan assets, historical and future expected real rates of return for equities and fixed income securities, and historical and expected inflation statistics. The expected long-term rate of return on plan assets to be used to develop net periodic benefit costs for fiscal 2007 is 9 percent for pension costs and 8.5 percent for OPEB costs.

18. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

A reconciliation of the funded status of the plans to the amounts recognized on the Consolidated Balance Sheets is presented below, using a measurement date of September 30:

	Pension		OPEB	
(Thousands)	**2006**	2005	**2006**	2005
Change in Benefit Obligation				
Benefit obligation at beginning of year	**$ 99,900**	$ 90,004	**$ 43,602**	$ 37,024
Service cost	**3,004**	2,600	**1,582**	1,297
Interest cost	**5,633**	5,302	**2,472**	2,181
Plan participants' contributions	**57**	60	**—**	—
Actuarial loss	**(742)**	5,859	**5,245**	4,603
Special termination benefit	**—**	—	**—**	72
Benefits paid	**(4,114)**	(3,925)	**(1,526)**	(1,575)
Benefit obligation at end of year	**$ 103,738**	$ 99,900	**$ 51,375**	$ 43,602
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 82,596**	$ 66,566	**$ 22,380**	$ 20,685
Actual return on plan assets	**7,296**	8,985	**2,026**	2,632
Employer contributions	**10,000**	10,910	**3,690**	638
Plan participants' contributions	**57**	60	**—**	—
Benefits paid	**(4,114)**	(3,925)	**(1,526)**	(1,575)
Fair value of plan assets at end of year	**$ 95,835**	$ 82,596	**$ 26,570**	$ 22,380
Funded status	**$ (7,903)**	$ (17,304)	**$ (24,805)**	$ (21,222)
Unrecognized actuarial loss	**28,458**	31,100	**22,095**	17,878
Unrecognized transition obligation	**—**	—	**2,527**	2,884
Unrecognized prior service cost	**490**	573	**428**	506
Unrecognized net initial obligation	**—**	(11)	**—**	—
Net amount recognized	**$ 21,045**	$ 14,358	**$ 245**	$ 46
Amounts recognized on Consolidated Balance Sheets				
Accrued benefit liability included in:				
Prepaid pension asset	**$ 21,045**	$ —	$ —	$ —
Accounts payable and other	**—**	—	**—**	(613)
Postemployment employee benefit liability	**—**	(3,521)	**245**	659
Intangible asset	**—**	573	**—**	—
Accumulated other comprehensive income	**—**	17,306	**—**	—
Net amount recognized	**$ 21,045**	$ 14,358	**$ 245**	$ 46

The accumulated benefit obligation (ABO) for the pension plans at September 30, 2006 and 2005, was $90.9 million and $86.1 million, respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Pursuant to SFAS No. 87, *"Employers Accounting for Pension"* (SFAS 87), the Company was required to record a $207,000 reduction to its minimum pension liability in fiscal 2005, which is included in Postemployment employee benefit liability on the Consolidated Balance Sheets.

The expected long-term rate of return is based on the asset categories in which the Company invests and the current expectations and historical performance for these categories.

The mix and targeted allocation of the pension and OPEB plans' assets are as follows:

Asset Allocation	2007 Target Allocation	Assets at Sept. 30, 2006	2005
U.S. equity securities	53%	53%	53%
International equity securities	18	18	19
Fixed income	29	29	28
Total	100%	100%	100%

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid during the following years:

(Thousands)	Pension	OPEB
2007	$ 4,312	$ 1,958
2008	4,505	2,079
2009	4,770	2,237
2010	4,931	2,306
2011	5,257	2,412
2012-2016	$ 31,052	$ 14,408

In fiscal 2004, the Company adopted FASB Staff Position *"Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (the Act)" (FSP 106-2). The adoption of FSP 106-2 resulted in a $300,000 reduction in expense in fiscal 2004 and a $3 million reduction in the accumulated postemployment benefit obligation. The estimated subsidy payments from the Act are:

Fiscal Year	Estimated Subsidy Payment (thousands)
2007	$ 100
2008	100
2009	200
2010	200
2011-2015	$ 1,300

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Pension Equalization Plan

The Company maintains an unfunded nonqualified pension equalization plan (PEP) that was established to provide employees with the full level of benefits as stated in the qualified plan without reductions due to various limitations imposed by the provisions of federal income tax laws and regulations. There were no plan assets in the nonqualified plan due to the nature of the plan. The Company recognized a $144,000 and $1.9 million net periodic PEP cost in fiscal 2006 and 2005, respectively. The PEP weighted average assumptions are identical to the qualified pension plan assumptions.

The PBO and ABO for the Company's unfunded PEP were $2.0 million and $1.9 million respectively, as of September 30, 2006, and $2.1 million and $1.9 million, respectively, as of September 30, 2005.

Voluntary Early Retirement Program

In September 2004, the Company offered a voluntary early retirement program to officers of NJR and its subsidiaries. The early retirement program resulted in $2.5 million being charged to Operations and maintenance expense in fiscal 2005.

Defined Contribution Plan

The Company offers an Employees' Retirement Savings Plan (Savings Plan) to eligible employees. The Company matches 50 percent of participants' contributions up to 6 percent of base compensation.

For represented NJRHS employees who are not eligible for participation in the defined benefit plan, the Company contributes between 2 and 3 percent of base compensation, depending on years of service, into the Savings Plan on their behalf.

The amount expensed and contributed for the matching provision of the Savings Plan was $1.1 million each in fiscal years 2006, 2005 and respectively.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

12. SELECTED QUARTERLY DATA (UNAUDITED)

A summary of financial data for each quarter of fiscal 2006 and 2005 follows. Due to the seasonal nature of the Company's businesses, quarterly amounts vary significantly during the fiscal year. In the opinion of management, the information furnished reflects all adjustments necessary for a fair presentation of the results of the interim periods.

(Thousands, except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
2006				
Operating revenues	**$ 1,164,576**	**$ 1,064,422**	**$ 536,103**	**$ 534,507**
Operating income (loss)	**$ 61,669**	**$ 104,942**	**$ (3,399)**	**$ (16,749)**
Net income (loss)	**$ 34,264**	**$ 60,201**	**$ (3,975)**	**$ (11,971)**
Earnings per share				
Basic	**$ 1.24**	**$ 2.16**	**$ (.14)**	**$ (.43)**
Diluted	**$ 1.23**	**$ 2.14**	**$ (.14)**	**$ (.43)**
2005				
Operating revenues	$ 853,988	$ 1,065,057	$ 544,280	$ 684,937
Operating income (loss)	$ 53,628	$ 88,295	$ 5,851	$ (9,406)
Net income (loss)	$ 30,202	$ 51,665	$ 1,835	$ (7,362)
Earnings per share				
Basic	$ 1.09	$ 1.87	$ .07	$ (.27)
Diluted	$ 1.06	$ 1.84	$ .07	$ (.27)

The sum of quarterly earnings per share may not equal annual earnings per share due to rounding.

13. COMMITMENTS AND CONTINGENT LIABILITIES

Cash Commitments

NJNG has entered into long-term contracts, expiring at various dates through 2022, for the supply, storage and delivery of natural gas. These contracts include current annual fixed charges of approximately $102.5 million at current contract rates and volumes, which are recovered through the BGSS.

As of September 30, 2006, there were NJR guarantees covering approximately $232 million of natural gas purchases and demand fee commitments of NJRES and NJNG not yet reflected in Accounts payable on the Consolidated Balance Sheet.

NJNG's capital expenditures are estimated at $66 million and $63 million in fiscal 2007 and 2008, respectively, and consist primarily of its construction program to support customer growth, maintenance of its distribution system and replacement needed under proposed pipeline safety rulemaking.

The Company's future minimum lease payments under various operating leases are less than $3.7 million annually for the next five years and $680,000 in the aggregate for all years thereafter.

Manufactured Gas Plant Remediation

NJNG has identified 11 former MGP sites, dating back to the late 1800s and early 1900s, which contain contaminated residues from the former gas manufacturing operations. Ten of the 11 sites in question were acquired by NJNG in 1952. Gas manufacturing operations ceased at these sites at least by the mid-1950s and, in some cases, had been discontinued many years earlier. All of the former gas manufacturing facilities were subsequently dismantled by NJNG or the previous owners. Since October 1989, NJNG has been operating under Administrative Consent Orders or Memoranda of Agreement with the NJDEP covering all 11 sites. These orders and agreements establish the procedures to be followed in developing a final remedial cleanup plan for each site. NJNG is currently involved in administrative proceedings with the NJDEP with respect to the MGP sites in question, as well as participating in various studies and investigations by outside consultants to determine the nature and extent of any such contaminated residues and to develop appropriate programs of remedial action, where warranted. Until September 2000, most of the cost of such studies and investigations had been shared under an agreement with the former owner and operator of 10 of the MGP sites, Jersey Central Power & Light Company (JCP&L), a subsidiary of FirstEnergy Corporation (FirstEnergy).

In September 2000, a revised agreement was executed pursuant to which NJNG is responsible for two of the sites, while JCP&L is responsible for the remaining eight sites. Also in September 2000, NJNG purchased a 20-year cost-containment insurance policy and an Environmental Response Compensation and Liability Insurance Policy (ERCLIP) for the two sites (see *Kemper Insurance Company Litigation* below). On September 14, 2004, the BPU approved a simultaneous transfer of properties whereby NJNG would take ownership of two sites. NJNG continues to participate in the investigation and remedial action and bears the cost related to the one MGP site that was not subject to the original cost-sharing agreement.

In June 1992, the BPU approved a remediation rider through which NJNG may, subject to BPU approval, recover its remediation expenditures, including carrying costs, over rolling 7-year periods. The BPU reviews the remediation recovery each year when NJNG files its annual report of expenditures. On April 12, 2006, the BPU approved a stipulation related to NJNG's 2004 filing, that maintained the existing recovery rate of approximately $19.2 million annually that recognizes remediation expenditures through June 2004. Currently, two SBC annual filings are pending BPU approval. On September 30, 2005, NJNG filed updated information regarding expenditures to SBC programs and activities, including MGP expenditures through June 30, 2005. While the SBC filing maintained the same overall rate, the filing proposed to reduce the portion related to the remediation rider recovery to $11.6 million of annual expenditures to reflect actual spending levels. In the subsequent annual filing in October 2006, NJNG filed to supersede its prior request, seeking a decrease to the existing remediation rider recovery from $19.2 million, annually, to $15.9 million, annually. As of September 30, 2006, $83.7 million of previously incurred remediation costs, net of recoveries from customers as well as received and anticipated insurance proceeds, are included in Regulatory assets on the Consolidated Balance Sheet. (See *Note 4. Regulatory Assets and Liabilities.)*

In March 1995, NJNG instituted an action for declaratory relief against 24 separate insurance companies in the Superior Court of New Jersey. These insurance carriers provided comprehensive general liability coverage to NJNG from 1951 through 1985. In July 1996, the complaint was amended

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

to name Kaiser-Nelson Steel and Salvage Company (Kaiser-Nelson) and its successors for environmental damages caused by Kaiser-Nelson's decommissioning of structures at several MGP sites. In September 2001, NJNG reached a favorable settlement with the insurance carrier that provided the majority of NJNG's coverage. This settlement involved a significant cash payment to NJNG, which was credited to the remediation rider, and was received in four installments ending October 2004. In January 2006, NJNG reached a settlement of all claims with Kaiser-Nelson, which included a cash payment that was received by NJNG and credited to the remediation rider. Consequently, NJNG has now dismissed or reached a settlement with all of its insurance carriers who provided comprehensive general liability coverage to NJNG in connection with the MGP sites.

NJNG is presently investigating the potential settlement of alleged Natural Resource Damage (NRD) claims that might be brought by the NJDEP concerning the three MGP sites. NJDEP has not made any specific demands for compensation for alleged injury to groundwater or other natural resources. NJNG's evaluation of these potential claims is in the early stages, and it is not yet possible to quantify the amount of compensation that NJDEP might seek to recover. NJNG anticipates any costs associated with this matter would be recoverable through the remediation rider.

NJNG is involved with environmental investigations and remedial actions at certain MGP sites. In September 2006, with the assistance of an outside consulting firm, NJNG updated an environmental review of the MGP sites, including a review of potential liability for investigation and remedial action. Based on this review, NJNG estimated at the time of the review that, exclusive of any insurance recoveries, total future expenditures to remediate and monitor the three MGP sites for which it is responsible, will range from $105.4 million to $174.6 million. NJNG's estimate of these liabilities is based upon known facts, existing technology and enacted laws and regulations in place when the review was completed. However, actual costs are expected to differ from these estimates. Where available information is sufficient to estimate the amount of the liability, it is NJNG's policy to accrue the full amount of such estimate. Where the information is sufficient only to establish a range of probable liability, and no point within the range is more likely than any other, it is NJNG's policy to accrue the lower end of the range. Accordingly, NJNG has recorded an MGP remediation liability and a corresponding Regulatory asset of $105.4 million on the Consolidated F ce Sheet. The actual costs to be incurred by NJNG are dependent upon several factors, including final determination of remedial action, c ing technologies and governmental regulations, the ultimate ability of other responsible parties to pay and any insurance recoveries. NJNG will continue to seek recovery of such costs through its remediation rider. If any future regulatory position indicates that the recovery of such costs is not probable, the related cost would be charged to income in the period of such determination.

Long Branch Litigation

Since July 2003, a series of complaints were filed in the New Jersey Superior Court against NJNG, NJR, JCP&L and FirstEnergy. The complaints were originally filed in Monmouth County and, as of February 2004, were designated as a Mass Tort Litigation (the "Mass Tort Litigation") for centralized case management purposes and transferred to the Bergen County Law Division. There were originally 528 complaints filed. All 528 complaints have been dismissed or settled.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Among other things, the complaints alleged personal injuries, wrongful death, survivorship actions, property damage and claims for medical monitoring stemming from the operation and remediation of the former MGP site in Long Branch, New Jersey. The relief sought included compensatory damages, the establishment of a medical monitoring fund, disgorgement of alleged profits, cost of cleanup and remediation, natural resource damages and punitive damages.

In December 2005, a confidential settlement between NJNG and the plaintiffs was finalized and approved by the New Jersey Superior Court in Bergen County.

JCP&L and FirstEnergy made a demand upon NJNG and NJR for indemnification pursuant to the September 2000 agreement between these entities and NJNG, whereby NJNG assumed responsibility for the Long Branch site. NJNG has agreed to honor the indemnification terms of the agreement.

NJNG's insurance carriers were initially notified of the claims, and Kemper Insurance Company (Kemper), under the ERCLIP, initially agreed to provide a defense and certain coverage, subject to a reservation of rights regarding various allegations in the complaints, typically not covered by insurance. However, as Kemper's defense and insurance obligations were not met, NJNG initiated litigation against Kemper (see *Kemper Insurance Company Litigation* below).

Management believes that litigation costs and the settlement amount are recoverable through insurance (subject to the outcome of the Kemper Insurance Company Litigation). Additionally, management believes that any liabilities not recoverable through insurance, except for punitive and personal injury damages, would be recoverable, with BPU approval, through the remediation rider. However, there can be no assurance as to the ultimate resolution of the recovery of these amounts or the impact on the Company's financial condition, results of operations or cash flows.

Twelve *pro se* matters have been filed against the Company and NJNG since February 26, 2005. These complaints were filed in the Superior Court of New Jersey Law Division, Bergen County and allege the same claims made in the Mass Tort Litigation. Five of these actions have been dismissed by the court. NJNG and the Company believe that the allegations in the complaints have no merit and are vigorously defending against them.

The amount of total liability, resulting from the *pro se* matters described in the preceding paragraph if any, and any related insurance recovery cannot be determined at this time; however, based on information and relevant circumstances known at this time, management does not believe these suits will have a material adverse effect on the Company's financial condition, results of operations or cash flows.

Kemper Insurance Company Litigation

In October 2004, NJNG instituted suit for declaratory relief against Kemper in the Superior Court of New Jersey, Law Division, Ocean County. The case is under active case management. Kemper provided insurance under an ERCLIP together with a cost containment coverage policy effective July 21, 2000. Prior to the institution of this suit, NJNG requested that Kemper defend and indemnify claims involving the Mass Tort Long Branch litigation (see *Long Branch Litigation* , above) and reimburse NJNG for remediation costs for the Long Branch site that exceed the self-insured retention.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA (Continued)

Kemper reserved its rights regarding various allegations in the Mass Tort Litigation and agreed to participate in the defense of that matter. Although Kemper has not denied coverage, it has not yet reimbursed NJNG for any costs incurred to date. In fiscal 2003, Kemper ceased its underwriting operations and voluntarily commenced a runoff of its business. The Illinois Department of Insurance has approved Kemper's runoff plan. Management believes that, with the exception of any liability for punitive and personal injury damages, any costs associated with Kemper's failure to meet its future obligations will be recoverable, with BPU approval, through the remediation rider.

There can be no assurance as to the ultimate resolution of this matter or the impact on the Company's financial condition, results of operations or cash flows.

Various

The Company is a party to various other claims, legal actions, complaints and investigations arising in the ordinary course of business. In the Company's opinion, the ultimate disposition of these matters will not have a material adverse effect on its financial condition, results of operations or cash flows.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of the end of the period reported on in this report, NJR has undertaken an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of its disclosure controls and procedures, pursuant to Rule 13a-15 of the Securities Exchange Act of 1934. Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that NJR's disclosure controls and procedures were effective with regard to the recording, processing, summarizing and reporting, within the time periods specified in the SEC's rules and forms, of information required to be disclosed by NJR in the reports that it files or submits under the Exchange Act.

Management's Annual Report on Internal Control over Financial Report

The report of management required under this ITEM 9A is contained in ITEM 8 of this Form 10-K under the caption "Management's Report on Internal Control over Financial Reporting."

ITEM 9A. CONTROLS AND PROCEDURES (Continued)

Attestation Report of Registered Public Accounting Firm

The attestation report required under this ITEM 9A is contained in ITEM 8 of this 10-K under the caption "Report of Independent Registered Public Accounting Firm."

Changes in Internal Control over Financial Reporting

There have been no significant changes in the Company's internal controls over financial reporting or in other factors that could significantly affect internal controls in the quarter ended September 30, 2006.

ITEM 9B. OTHER INFORMATION

None

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information concerning the Board of Directors of the Company, the members of the Company's Audit Committee, the Company's Audit Committee Financial Expert, the Company's Code of Ethics and compliance with Section 16(a) of the Securities Exchange Act of 1934 is incorporated by reference to the Company's Proxy Statement for the 2007 Annual Meeting of Shareowners (the "Proxy Statement"), which will be filed with Securities and Exchange Commission (SEC) pursuant to Regulation 14A on or about December 22, 2006.

Executive Officers

The information required by this item is incorporated by reference to Item 4A. "Executive Officers of the Company" of this report.

ITEM 11. EXECUTIVE COMPENSATION

Information required by this Item is incorporated by reference from the Registrant's Proxy Statement.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information required by this Item is incorporated by reference from the Registrant's Proxy Statement.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information required by this Item is incorporated by reference from the Registrant's Proxy Statement.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information required by this Item is incorporated by reference from the Registrant's Proxy Statement.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. Financial Statements.

All Financial Statements of the Registrant are filed as part of this report and included in Item 8 of Part II of this Form 10-K.

(a) 2. Financial Statement Schedules–See Index to Financial Statement Schedules In Item 8.

(a) 3. Exhibits–See Exhibit Index on page 108.

I' 'X TO FINANCIAL STATEMENT SCHEDULES

	Page
Schedule II—Valuation and qualifying accounts and reserves for each of the three years in the period ended September 30, 2006	106

Schedules other than those listed above are omitted because they are not required or are not applicable, or the required information is shown in the financial statements or notes thereto.

New Jersey Resources

Schedule II

VALUATION AND QUALIFYING ACCOUNTS
YEARS ENDED SEPTEMBER 30, 2006, 2005 and 2004

(Thousands)

CLASSIFICATION	BALANCE AT BEGINNING OF YEAR	ADDITIONS CHARGED TO EXPENSE	*OTHER (1)*	BALANCE AT END OF YEAR
2006:				
Allowance for Doubtful Accounts	**$ 5,297**	**$ 3,612**	**$ (6,230)**	**$ 2,679**
2005:				
Allowance for Doubtful Accounts	$ 5,304	$ 6,128	$ (6,135)	$ 5,297
2004:				
Allowance for Doubtful Accounts	$ 5,635	$ 2,607	$ (2,938)	$ 5,304

Notes: *(1) Uncollectible accounts written off, less recoveries and changes to adjust reserve to appropriate level.*

S NATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

NEW JERSEY RESOURCES CORPORATION

(Registrant)

Date: November 22, 2006

By:/s/ GLENN C. LOCKWOOD

Glenn C. Lockwood
Senior Vice President and
Chief Financial Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated:

Nov. 22, 2006	/s/ LAURENCE M. DOWNES Laurence M. Downes Chairman, President and Chief Executive Officer Director	Nov. 22, 2006	/s/ DOROTHY K. LIGHT Dorothy K. Light Director
Nov. 22, 2006	/s/ GLENN C. LOCKWOOD Glenn C. Lockwood Senior Vice President and Chief Financial Officer (Principal Accounting Officer)	Nov. 22, 2006	/s/ J. TERRY STRANGE J. Terry Strange Director
. 22, 2006	/s/ NINA AVERSANO Nina Aversano Director	Nov. 22, 2006	/s/ DAVID A. TRICE David A. Trice Director
Nov. 22, 2006	/s/ LAWRENCE R. CODEY Lawrence R. Codey Director	Nov.22, 2006	/s/ WILLIAM H. TURNER William H. Turner Director
Nov. 22, 2006	/s/ M. WILLIAM HOWARD, JR. M. William Howard, Jr. Director	Nov. 22, 2006	/s/ GARY W. WOLF Gary W. Wolf Director
Nov. 22, 2006	/s/ JANE KENNY Jane Kenny Director	Nov. 22, 2006	/s/ GEORGE R. ZOFFINGER George R. Zoffinger Director
Nov. 22, 2006	/s/ ALFRED C. KOEPPE Alfred C. Koeppe Director		

F 'IBIT INDEX

Exhibit Number	Exhibit Description
3.1	Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3-1 to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
3.2	By-Laws of the Company (incorporated by reference to Exhibit 4-2 to Registration Statement on Form S-8 as filed with the SEC (No. 333-59013))
4.1	Specimen Common Stock Certificates (incorporated by reference to Exhibit 4-1 to Registration Statement No. 033-21872)
4.2	Indenture of Mortgage and Deed of Trust between NJNG and Harris Trust and Savings Bank, as Trustee, dated April 1, 1952, as supplemented by twenty-one Supplemental Indentures (incorporated by reference to Exhibit 4(g) to Registration Statement No. 002-9569)
4.2(a)	Twenty-Second Supplemental Indenture, dated as of October 1, 1993 (incorporated by reference to Exhibit 4.2(V) to the 1993 Annual Report on Form 10-K for the year ended September 30, 1994)
4.2(b)	Twenty-Fifth Supplemental Indenture, dated as of July 15, 1995 (incorporated by reference to Exhibit 4.2(Y) to the Annual Report on Form 10-K for the year ended September 30, 1995, as filed on December 29, 1995)
4.2(c)	Twenty-Sixth Supplemental Indenture, dated as of October 1, 1995 (incorporated by reference to Exhibit 4.2(X) to the Annual Report on Form 10-K for the year ended September 30, 1995, as filed on December 29, 1995)
4.2(d)	Twenty-Seventh Supplemental Indenture, dated as of September 1, 1997 (incorporated by reference to Exhibit 4.2(J) to the Annual Report on Form 10-K as filed on December 29, 1997)
4.2(e)	Twenty-Eighth Supplemental Indenture, dated as of January 1, 1998 (incorporated by reference to Exhibit 4.2(K) to the Annual Report on Form 10-K for the year ended September 30, 1998, as filed on December 24, 1998)
4.2(f)	Twenty-Ninth Supplemental Indenture, dated as of April 1, 1998 (incorporated by reference to Exhibit 4.2(L) to the Annual Report on Form 10-K for the year ended September 30, 1988, as filed on December 24, 1998)
4.2(g)	Thirtieth Supplemental Indenture, dated as of December 1, 2003 (incorporated by reference to Exhibit 4.2(J) to the Annual Report on Form 10-K for the year ended September 30, 2003, as filed on December 16, 2003)
[illegible](n)	Thirty-First Supplemental Indenture, dated as of October 1, 2005 (incorporated by reference to Exhibit 4.2(I) to the Annual Report on Form 10-K for the year ended September 30, 2005, as filed on November 29, 2005)

	$225,000,000 Revolving Credit Facility Credit Agreement (the "$225,000,000 Revolving Credit Facility") by and among NJNG, PNC Bank, NA as Administrative Agent, the banks party thereto, JPMorgan Chase Bank, NA and Fleet National Bank, as Syndication Agents, Bank Of Tokyo-Mitsubishi Trust Company and Citicorp North America, Inc., As Documentation Agents and PNC Capital Markets, Inc., as Lead Arranger, dated as of December 16, 2004 (incorporated by reference to Exhibit 4-2 to the Quarterly Report on Form 10-Q as filed on February 7, 2005)
4.3(a)	First Amendment dated as of August 31, 2005 to the $225,000,000 Revolving Credit Facility, dated as of December 16, 2004 (incorporated by reference to Exhibit 4-3A to the Annual Report on Form 10-K for the year ended September 30, 2005, as filed on November 29, 2005)
4.3(b)	Second Amendment and Consent dated as of November 15, 2005 to the $225,000,000 Revolving Credit Facility, dated as of December 16, 2004 (incorporated by reference to Exhibit 4-3B to the Annual Report on Form 10-K for the year ended September 30, 2005, as filed on November 29, 2005)
4.4	$275,000,000 Revolving Credit Facility Credit Agreement (the "$275,000,000 Revolving Credit Facility") by and among the Company, PNC Bank, NA as Administrative Agent, the banks party thereto, JPMorgan Chase Bank, NA and Fleet National Bank, as Syndication Agents, Bank Of Tokyo-Mitsubishi Trust Company and Citicorp North America, Inc., As Documentation Agents and PNC Capital Markets, Inc., as Lead Arranger, dated as of December 16, 2004 (incorporated by reference to Exhibit 4-1 to the Quarterly Report on Form 10-Q as filed on February 7, 2005)
4.4(a)	First Amendment dated as of November 15, 2005 to the $275,000,000 Revolving Credit Facility, dated as of December 16, 2004 (incorporated by reference to Exhibit 4-4A to the Annual Report on Form 10-K for the year ended September 30, 2005, as filed on November 29, 2005)
4.5	$30,000,000 Credit Agreement by and among the Company, NJR Energy Services Company, as the Borrowers, and Bank of Tokyo-Mitsubishi UFJ Trust Company, as the Bank*, dated as of October 12, 2006
4.6	$60,000,000 Note Purchase Agreement by and among NJNG and J.P. Morgan Securities Inc., as Placement Agent, dated March 15, 2004 (incorporated by reference to Exhibit 4-1 to the Quarterly Report on Form 10-Q as filed on May 10, 2004)
4.7	$25,000,000 Note Purchase Agreement by and among NJR and J.P. Morgan Securities Inc., as Placement Agent, dated March 15, 2004 (incorporated by reference to Exhibit 4-2 to the Quarterly Report on Form 10-Q as filed on May 10, 2004)
10.2	Retirement Plan for Represented Employees, as amended on October 1, 1984 (incorporated by reference to Registration Statement No. 002-73181)
10.3	Retirement Plan for Non-Represented Employees, as amended October 1, 1985 (incorporated by reference to Registration Statement No. 002-73181)
10.4	Supplemental Retirement Plans covering each of the Executive Officers (incorporated by reference to Exhibit 10.9 to the Annual Report on Form 10-K for the year ended September 30, 1986)

(a)	Service Agreement for Rate Schedule FTS-4 by and between NJNG and Texas Eastern Transmission Company, dated as of June 21, 1995 (incorporated by reference to Exhibit 10-5A to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.5(b)	Service Agreement for Rate Schedule SS-1by and between NJNG and Texas Eastern Transmission Company, dated as of June 21, 1995 (incorporated by reference to Exhibit 10-5B to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.5(c)	Service Agreement for Rate Schedule CDS by and between NJNG and Texas Eastern Transmission Company, dated as of November 15, 1995 (incorporated by reference to Exhibit 10-5C to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.6	The Company's Officer Incentive Plan effective as of October 1, 1986 (incorporated by reference to Exhibit 10-6 to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.7	Lease Agreement between NJNG, as Lessee and State Street Bank and Trust Company of Connecticut, National Association, as Lessor for NJNG's Headquarters Building dated December 21, 1995 (incorporated by reference to Exhibit 10-7 to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.10	The Company's Long-Term Incentive Compensation Plan, as amended, effective as of October 1, 1995 (incorporated by reference to Appendix A to the Proxy Statement for the 1996 Annual Meeting as filed on January 4, 1996)
10.12	Employment Continuation Agreement between the Company and Laurence M. Downes dated June 5, 1996 (incorporated by reference to Exhibit 10-12 to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.12(a)	Amendment to the Employment Continuation Agreement between the Company and Laurence M. Downes dated as of December 1, 1997 (incorporated by reference to Exhibit 10-12A to the Annual Report on Form 10-K for the year ended September 30, 1997, as filed on December 29, 1997)
10.12(b)	Revised Schedule of Officer Employee Continuation Agreements (incorporated by reference to Exhibit 10-12B to the Annual Report on Form 10-K for the year ended September 30, 1997, as filed on December 29, 1997)
}	Gas Sales Agreements between NJNG and Alberta Northeast Gas Limited dated as of February 7, 1991 (incorporated by reference to Exhibit 10-13 to the Annual Report on Form 10-K for the year ended September 30, 1992)
10.14	Gas Transportation Contract for Firm Reserved Service between NJNG and Iroquois Gas Transmission System, L.P., dated February 7, 1991 (incorporated by reference to Exhibit 10-14 to the Annual Report on Form 10-K for the year ended September 30, 1992)

.5	Service Agreement between NJNG and CNG Transmission Corporation dated as of December 1, 1993 (incorporated by reference to Exhibit 10-15 to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.15(a)	Service Agreement between NJNG and CNG Transmission Corporation dated as of December 1, 1993 (incorporated by reference to Exhibit 10-15A to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.15(b)	Service Agreement between NJNG and CNG Transmission Corporation dated December 1, 1993 and, as amended, as of December 21, 1993 (incorporated by reference to Exhibit 10-15B to the Annual Report on Form 10-K for the year ended September 30, 1996, as filed on December 30, 1996)
10.16	Summary of Company's Non-Employee Director Compensation (incorporated by reference to Exhibit 10.16 to the Current Report on Form 8-K as filed on November 17, 2006.)
21.1	Subsidiaries of the Registrant*
23.1	Consent of Independent Registered Public Accounting Firm*
31.1	Certification of the Chief Executive Officer pursuant to section 302 of the Sarbanes-Oxley Act*
31.2	Certification of the Chief Financial Officer pursuant to section 302 of the Sarbanes-Oxley Act*
32.1	Certification of the Chief Executive Officer pursuant to section 906 of the Sarbanes-Oxley Act* †
32.2	Certification of the Chief Financial Officer pursuant to section 906 of the Sarbanes-Oxley Act* †

* *Filed herewith*

† *This certificate accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 or any other provision of the Securities Exchange Act of 1934, as amended.*

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Exhibit 4.5

Execution version

CREDIT AGREEMENT

This **CREDIT AGREEMENT** (this "Agreement") is dated as of October 12, 2006 and is by and among NEW JERSEY RESOURCES CORPORATION ("NJRC"), a New Jersey corporation, NJR ENERGY SERVICES COMPANY ("NJRESC"), a New Jersey corporation (a "Borrower" and NJRC and NJRESC, together, the "Borrowers") and BANK OF TOKYO-MITSUBISHI UFJ TRUST COMPANY, a New York trust company (the "Bank").

WHEREAS, the Borrowers have requested the Bank to provide a revolving credit facility to the Borrowers in an aggregate principal amount not to exceed $30,000,000;

WHEREAS, the Borrowers are jointly and severally liable as obligors under this Agreement; and

WHEREAS, t he Borrowers desire the Bank to extend credit to the Borrowers, and the Bank agrees to extend credit to the Borrowers, all in accordance with the terms and conditions set forth herein.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby confirmed and acknowledged, the Borrowers and the Bank hereby agree as follows:

Section 1. Definitions and Interpretation .

As used herein, the following terms shall have the meanings set forth below:

(a) " Affiliate " shall mean, with respect to any Person, any other Person that, directly or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, such first Person.

(b) " Agreement Date " shall mean the date first set above, such date being the date as of which this Agreement was e.. ..ted and delivered by the parties hereto.

(c) " Applicable Law " shall mean, anything in Section 13 to the contrary notwithstanding, (i) all applicable common law and principles of equity and (ii) all applicable provisions of all (A) constitutions, statutes, rules, regulations and orders of governmental bodies, (B) Governmental Approvals and (C) orders, decisions, judgments and decrees of all courts and arbitrators.

(d) "Authorized Officer" shall mean those individuals, designated by written notice to the bank from the Borrowers, authorized to execute notices, reports and other

documents on behalf of the Borrowers required hereunder. The Borrowers may amend such list of individuals from time to time by giving written notice of such amendment to the Bank.

(e) " Bank's Office " shall mean Bank of Tokyo-Mitsubishi UFJ Trust Company, 1251 Avenue of the Americas, 12th l New York, New York 10020-1104.

(f) " Business Day " shall mean any day except a day (i) which is a Saturday or a Sunday, or (ii) on which commercial banks are not required or authorized to remain open for the regular transaction of international and domestic business in the City of New York.

(g) " Consolidated Income from Operations " for any period of determin ation shall mean (i) the sum of net income (provided that there shall be excluded from net in come: (a) any extraordinary items of gain or loss (including, without limitation, those items created by mandated changes in accounting treatment), and (b) any gain or loss of any Person accounted for on the equity method except to the extent of cash distributions received by NJRC or any Subsidiary of NJRC during the period of determination with respect to any gain of any Person accounted for on the equity method), depreciation, amortization, other non-cash charges to net income, interest expense and income tax expense minus (ii) non-cash credits to net income, in each case of NJRC and its Subsidiaries for such period determined and consolidated in accordance with GAAP.

(h) " Consolidated Interest Ex pense " for any period of determination shall mean interest expense for such period of NJRC and its Subsidiaries determined on a consolidated basis in accordance with GAAP.

(i) " Consolidated Shareholders' Equity " shall mean as of any date of determination the sum of the amounts under the headings "Common Shareholders' Equity" and "Preferred Shareholders' Equity" on the balance sheet, prepared in accordance with GAAP, for NJRC and its Subsidiaries on a consolidated basis as of such date of determination.

(j) " Consolidated Total Capitalization " shall mean as of any date of determination the sum of (i) Consolidated Total Indebtedness, plus (ii) Consolidated Shareholders' Equity.

(k) " Consolidated Total Indebtedness " shall mean as of any date of determination total Indebtedness, without duplication, of NJRC and its Subsidiaries.

(l) " Credit Agreement Related Claim " shall mean any claim (whether sounding in tort, contract or otherwise) in any way related to, arising out of, or connected with, this Agreement, or the relationships established hereunder or thereunder, whether such claim arises or is asserted before or after the Agreement Date.

(m) " Credit Facility " shall have the meaning ascribed to such term in Section 2 hereof.

(n) " Credit Facility Termination Date " shall mean October 12, 2009.

(o) " Default " shall mean any condition or event that constitutes an Event of Default or that with the giving of notice or lapse of time or both would, unless cured or waived, become an Event of Default.

(p o) " Dollars " and the sign " $ " shall each refer to the lawful currency of the United States of America.

(q) " Environmental Laws " shall mean as of any date the Comprehensive Environmental Response Compensation and Liability Act, the Hazardous Materials Transportation Act, the Resource Conservation and Recovery Act, the Federal Water Pollution Control Act, the Toxic Substances Control Act, and the Occupational Safety and Health Act, as such laws have been amended or supplemented, and any Federal, state, or local statute, ordinance, rule or regulation in effect.

(r) " ERISA " shall mean the Employee Retirement Income Security Act of 1974, as amended from time to time.

(s) " Event of Default " shall have the meaning ascribed to such term in Section 11 of this Agreement.

(t) " GAAP " shall mean generally accepted accounting principles applicable in the United States set forth from time to time in the opinions and pronouncements of the Accounting Principles Board and the American Institute of Certified Public Accountants and statements and pronouncements of the Financial Accounting Standards Board (or agencies with similar functions of comparable stature and authority within the U.S. accounting profession), which are applicable to the circumstances as of the date of determination.

(u) " Governmental Approval " shall mean any authorization, consent, approval, license or exemption of, registration or filing with, or report or notice to, a governmental unit.

(v) " Guaranty of any Person " shall mean any obligation of such Person guaranteeing or in effect guaranteeing any liability or obligation of any other Person in any manner, whether directly or indirectly, including any agreement to indemnify or hold harmless any other Person, any performance bond or other suretyship arrangement and any other form of assurance against loss, except endorsement of negotiable or other instruments for deposit or collection in the ordinary course of business.

(w) " Hedging Contract Policies " shall mean the written internal policies and

procedures with respect to hedging or trading of gas contracts or other commodity, hedging contracts of any kind, or any derivatives or other similar financial instruments of NJRC and its Subsidiaries, as in effect on the date of this Agreement and as hereafter amended from time to time , a copy of which has been delivered to the Bank.

(x) " Hedging Transaction " shall mean any transaction entered into by a Loan Party or any of its Subsidiaries in accordance with the Hedging Contract Policies.

(y) " Hybrid Security " shall mean any of the following: (i) beneficial interests issued by a trust which constitutes a Subsidiary of the Borrowers , substantially all of the assets of which trust are unsecured Indebtedness of the Borrowers or any Subsidiary of the Borrowers or proceeds thereof, and all payments of which Indebtedness are required to be, and are, distributed to the holders of beneficial interests in such trust promptly after receipt by such trust, or (ii) any shares of capital stock or other equity interest that, other than solely at the option of the issuer thereof, by their terms (or by the terms of any security into which they are convertible or exchangeable) are, or upon the happening of an event or the passage of time would be, required to be redeemed or repurchased, in whole or in part, or have, or upon the happening of an event or the passage of time would have, a redemption or similar payment.

(z) " Indebtedness " shall mean, as to any Person at any time, any and all indebtedness, obligations or liabilities (whether matured or unmatured, liquidated or unliquidated, direct or indirect, absolute or contingent, or joint or several) of such Person for or in respect of: (i) borrowed money, (ii) amounts raised under or liabilities in respect of any note purchase or acceptance credit facility, (iii) reimbursement obligations (contingent or otherwise) under any letter of credit, currency swap agreement, interest rate swap, cap, collar or floor agreement or other interest rate or currency exchange rate management device, (iv) any other transaction (including forward sale or purchase agreements, capitalized leases and conditional sales agreements) having the commercial effect of a borrowing of money entered into by such Person to finance its operations or capital requirements (but not including trade payables and accrued expenses incurred in the ordinary course of business which are not represented by a promissory note or other evidence of indebtedness and which are not more than thirty (30) days past due), (v) any Hedging Transaction, to the extent that any indebtedness, obligations or liabilities of such Person in respect thereof constitutes "indebtedness" as determined in accordance with GAAP, (vi) any Guaranty of any Hedging Transaction described in the immediately preceding clause (v), (vii) any Guaranty of Indebtedness for borrowed money, (viii) any Hybrid Security described in clause (i) of the definition of Hybrid Security, or (ix) the mandatory repayment obligation of the issuer of any Hybrid Security described in clause (ii) of the definition of Hybrid Security.

(aa) " Interest Payment Date " shall mean the last Business Day of each calendar month and the Credit Facility T[illegible]ination Date.

(bb) " Lien " shall mean any mortgage, deed of trust, pledge, lien, security interest, charge or other encumbrance or security arrangement of any nature whatsoever, whether voluntarily or involuntarily given, including any conditional sale or title retention arrangement,

and any assignment, deposit arrangement or lease intended as, or having the effect of, security and any filed financing statement or other notice of any of the foregoing (whether or not a lien or other encumbrance is created or exists at the time of the filing).

(cc) " Loan " shall mean any loan of Dollars made by the Bank to the Borrowers under Section 3 of this Agreement.

(dd) " Materially Adverse Effect " shall mean, (i) with respect to any Person, any materially adverse effect on such Person's assets, liabilities, financial condition or results of operations, (ii) with respect to any contract, agreement or other obligation (other than this Agreement), any materially adverse effect, as to any party thereto, upon the binding nature thereof or the validity or enforceability thereof and (iii) with respect to this Agreement, any materially adverse effect on the legality, binding nature, validity or enforceability thereof.

(ee) " Maximum Permissible Rate " shall mean, with respect to interest payable on any amount, the rate of interest on such amount that, if exceeded, could, under Applicable Law, result in (i) civil or criminal penalties being imposed on the Bank or (ii) the Bank's being unable to enforce payment of (or, if collected, retain) all or any part of such amount or the interest payable thereon.

(ff) " Official Body " shall mean any national, federal, state, local or other government or political subdivision or any agency, authority, board, bureau, central bank, commission, department or instrumentality of either, or any court, tribunal, grand jury or arbitrator, in each case whether foreign or domestic.

(gg) " Overnight Fed Funds Open Rate " shall mean, for any day, a fluctuating interest rate per annum equal to the weighted average of the rates on overnight federal funds transactions with members of the Federal Reserve System arranged by federal funds brokers, as published for such day (and, if such day is not a Business Day, for the next preceding Business Day) by the Federal Reserve Bank of New York as posted on the page entitled "FED FUNDS OVERNIGHT & TERM" on a Bloomberg Terminal, referenced in Exhibit A hereto or, if such rate is not so published for any day that is a Business Day, the average of the quotations for such day on such transactions received by the Bank from three federal funds brokers of recognized standing selected by the Bank.

(hh) " Overnight F ed Funds Rate Loan " shall mean any Loan that bears interest at the Overnight Fed Funds Open Rate.

(ii) " Permitted Liens " shall mean any and all (i) Liens for Taxes, assessments or other governmental charges or levies r the time delinquent or thereafter payable without penalty; (ii) Liens in favor of carriers, materialmen, warehousemen, mechanics, la_ .ords,

suppliers, lessors or other like Liens incurred in the ordinary course of business for sums not overdue and Liens of landlords securing obligations to pay lease payments that are not yet overdue or in default;(iii) pledges or deposits made in the ordinary course of business to secure payment of workmen's compensation, or to participate in any fund in connection with workmen's compensation, unemployment insurance, old-age pensions or other social security programs; (iv) any Lien arising out of judgments or awards but only to the extent that the creation of any such Lien shall not be an event or condition which, with or without notice or lapse of time or both, would cause Borrower to be in violation of Section 11(i); (v) security interests in favor of lessors of personal property, which property is the subject of a true lease; (vi) good-faith pledges or deposits made in the ordinary course of business to secure performance of bids, tenders, contracts (other than for the repayment of borrowed money) or leases, not in excess of the aggregate amount due thereunder, or to secure statutory obligations, or surety, appeal, indemnity, performance or other similar bonds required in the ordinary course of business; (vii) encumbrances consisting of zoning restrictions, easements, rights-of-way or other restrictions on the use of real property and minor defects to title to real property, none of which materially impairs the use of such property or the value thereof; (viii) Liens on property leased by any Borrower or Subsidiary of a Borrower securing obligations of such Borrower or Subsidiary to the lessor under such leases, to the extent the payments or other amounts due and owing under any such lease constitute Indebtedness; (ix) any Lien existing on the date of this Agreement and described on Schedule A, provided, that, to the extent any such Lien secures Indebtedness permitted hereunder, such Lien may continue to secure any renewals or extensions of such Indebtedness permitted so long as (A) the principal amount of the Indebtedness secured by any such Lien is not hereafter increased and (B) no additional assets become subject to such Lien, such Indebtedness is permitted; (x) Purchase Money Security Interests, provided, that the aggregate amount of loans and deferred payments secured by such Purchase Money Security Interests shall not exceed $20,000,000 (excluding for the purpose of this computation any loans or deferred payments secured by Liens described on Schedule A); (xi) the following, (A) if the validity or amount thereof is being contested in good faith by appropriate and lawful proceedings diligently conducted so long as levy and execution thereon have been stayed and continue to be stayed or (B) if a final judgment is entered and such judgment is discharged within thirty (30) days of entry, and could not be reasonably expected to result in a Material Adverse Effect: (1) claims or Liens for Taxes due and payable and subject to interest or penalty, provided that the applicable Borrower maintains such reserves or other appropriate provisions as shall be required by GAAP and pays all such Taxes forthwith upon the commencement of proceedings to foreclose any such Lien; (2) claims, Liens or encumbrances upon, and defects of title to, real or personal property, including any attachment of personal or real property or other legal process prior to adjudication of a dispute on the merits; or (3) claims or Liens of mechanics, materialmen, warehousemen, carriers, or other statutory nonconsensual Liens; and (xii) any other Liens disclosed by the Borrowers to the Bank and consented to in writing by the Bank.

(jj) "Person" shall mean any individual, sole proprietorship, corporation, partnership, trust, unincorporated association, mutual company, joint stock company, trade association or other business organization.

(kk) " Post-Default Rate " shall mean a rate of interest per annum equal to the Prime Rate as in effect from time to time plus two percent (2%).

(ll) " Prime Rate " shall mean the rate of interest per annum publicly announced by the Bank from time to time in the (f New York as its "prime rate", which rate of interest may not be the lowest or best rate of interest offered by the Bank at any given time to any class of borrower. Any change in the Prime Rate shall result in an immediate corresponding change in any rate of interest based on the Prime Rate.

(mm) " Purchase Money Security Interest " shall mean Liens upon tangible personal property securing loans to any Borrower or Subsidiary of a Borrower or deferred payments by such Borrower or Subsidiary for the purchase of such tangible personal property.

(nn) " SEC " shall mean the Securities and Exchange Commission or any governmental agencies substituted therefor.

(oo) " SEC Filings " shall mean NJRC's Form 10-K, filed with the SEC for the fiscal year ended September 30, 2005 and Forms 10-Q, the first filed with the SEC for the fiscal quarter ended December 31, 2005, the second filed with SEC for the fiscal quarter ended March 31, 2006 and the third filed with the SEC for the fiscal quarter ended June 30, 2006.

(pp) " Subsidiary " shall mean, with respect to any Person, any other Person (i) the securities of which having ordinary voting power to elect a majority of the board of directors (or other persons having similar functions) or (ii) the other ownership interests of which ordinarily constituting a majority voting interest, are at the time, directly or indirectly, owned or controlled by such first Person, or by one or more of its Subsidiaries, or by such first Person and one or more of its Subsidiaries; unless otherwise specified, "Subsidiary" means a Subsidiary of the Borrowers.

(qq) " Tax " shall mean any federal, state or foreign tax, assessment or other governmental charge or levy (including withholding tax) upon a Person or upon its assets, revenues, income or profits.

Section 2. Terms of the Credit .

(a) Upon the terms and conditions of this Agreement, and in reliance upon the representations and warranties of the b. .owers set forth in Section 8 hereof, the Bank shall, from time to time during the period from the Agreement Date to the Credit Facility Termination Date, extend credit to the any of the Borrowers in the form of Loans (the " Credit Facility "). The sum of the aggregate principal amounts of all outstanding Loans shall not at any time exceed Thirty Million United States Dollars (U.S.$30,000,000.00) (the " Commitment "). Within the foregoing limits, the Borrowers may borrow Loans, repay Loans, prepay Loans (to the extent permitted under Sections 3 hereof), and re-borrow Loans on or after the Agreement Date up to

the Business Day before the Credit Facility Termination Date, in accordance with the terms hereof.

(b) The Borrowers may reduce the Commitment by giving the Bank notice (which shall be irrevocable) thereof no later than 10:00 a.m. (New York time) on the fifth Business Day before the requested date of such reduction.

(c) Each Borrower acknowledges and agrees that each Borrower shall be liable, on an conditional joint and several basis, for all of Loans and other obligations hereunder, and further acknowledges and agrees that Loans to any Borrower inure to the mutual benefit of all of the Borrowers and that the Bank is relying on the unconditional joint and several liability of the Borrowers in extending Loans hereunder.

Section 3. The Loans .

(a) The Loans shall be made in integral multiples of $500,000.00.

(b) For each proposed Loan, a Borrower shall give the Bank written notice of its proposal (which notice shall be irrevocable) no later than 9:00 a.m. (New York time) on the disbursement date for such Loan that is an Overnight Fed Funds Rate Loan. Each such notice shall specify (i) the requested disbursement date of the proposed Loan, which disbursement date shall be a Business Day, and (ii) the amount of such proposed Loan. Such notice for the extension of a Loan shall be (i) executed by purportedly duly authorized officers of such Borrower and (ii) made by telecopier, or telex, to be confirmed in writing or by telephone. A Borrower shall notify the Bank in writing of the names of their respective officers authorized to request Loans on behalf of the Borrower and shall provide the Bank with the specimen signatures of such officers. The proceeds of each Loan shall be disbursed by the Bank by crediting a Borrower's designated account at ICAP Futures, L.L.C., until further written notice by Borrower, with immediately available funds or in such other manner as may be acceptable to the Borrower and the Bank. Subject to the terms and conditions of this Agreement, if a Borrower shall properly and timely request a Loan under this subsection 3(b), then the Bank shall disburse the proceeds of such Loan no later than 12:00 p.m. (New York time) on the disbursement date therefor.

(c) Subject to Section 6 below, the Borrowers may, at any time and from time to time, prepay Loans in whole or in part together with accrued interest, except that any partial prepayment shall be in an aggregate principal amount of at least $500,000.00. A Borrower shall give the Bank written notice of each prepayment no later than 12:00 noon (New York time), on the date of such prepayment. I written notice of prepayment shall specify the date on which prepayment is to be made and the amount to be prepaid.

(d) The Borrowers shall repay to the Bank on the Credit Facility Termination Date the aggregate principal of Loans outstanding on such date.

Section 4. Interest .

Unless an Event of Default is continuing, each Loan shall bear interest on the outstanding principal amount thereof at the applicable Overnight Fed Funds Open Rate of interest plus 0.50%; Interest so accrued on each Loan shall be due and payable in arrears to the l by the Borrowers on the Loan's Interest Payment Date(s). Nothing contained in this Agreement or in any other documentation for the Loans shall require the Borrowers at any time to pay interest at a rate exceeding the Maximum Permissible Rate. If the interest payable to the Bank on any date would exceed the maximum amount permitted by the Maximum Permissible Rate, such interest payment shall be reduced automatically to such maximum permitted amount, and interest for any subsequent period, to the extent less than the maximum amount permitted for such period by the Maximum Permissible Rate, shall be increased by the unpaid amount of such reduction. During an Event of Default, each Loan (whether or not due) and, to the maximum extent permitted by Applicable Law, each other amount due and payable hereunder shall bear interest at the applicable Post-Default Rate, which interest shall be payable on demand. Interest payable under this Agreement shall be calculated on the basis of a year of 360 days and paid on the actual number of days elapsed.

Section 5. Payments by the Borrowers .

(a) Time, Place and Manner . All payments due to the Bank under this Agreement shall be made to the Bank at the Bank's Office or at such other address in the City of New York as the Bank may designate. Except as otherwise specified in this Agreement, a payment shall not be deemed to have been made on any day unless such payment has been received at the required place of payment, in Dollars and in funds immediately available, no later than 2:00 p.m. (New York time) on such day.

(b) No Reductions . All payments due to the Bank under this Agreement shall be made by each Borrower without any reduction or deduction whatsoever, including any reduction or deduction for any set-off, recoupment, counterclaim (whether sounding in tort, contract or otherwise) or Tax, except for any withholding or deduction for Taxes required to be withheld or deducted under Applicable Law.

(c) Taxes . If any Tax is required to be withheld or deducted from, or is otherwise payable by the any Borrower in connection with, any payment due to the Bank under this Agreement, such Borrower (i) shall, if required, withhold or deduct the amount of such Tax from such payment and, in any case, pay such Tax to the appropriate taxing authority in accordance with Applicable Law and (ii) shall pay to the Bank such additional amounts as may be necessary so that the net amount received by the Bank with respect to such payment, after withholding or deducting all Taxes required to be withheld or deducted, is equal to the full amount payable under this Agreement. If any withheld or deducted from any payment due to the Bank under this Agreement, such Borrower shall, within thirty (30) days after the of such payment, furnish to the Bank the original or a certified copy of a receipt for such Tax from the applicable taxing authority.

(d) Authorization to Charge Accounts . Each Borrower hereby authorizes the Bank, if and to the extent any amount payable by any Borrower under this Agreement is not otherwise paid when due, to charge such amount against any or all of the accounts any Borrower maintains with any branch or office of the Bank or its Affiliates (as if the Bank and its Affiliates were one and the same entity), with the Borrowers remaining liable for any deficiency.

(e) Extension of Payment Dates . Unless otherwise provided herein, whenever any payment to the Bank under this Agreement shall be due (otherwise than by reason of acceleration) on a day that is not a Business Day, the date of payment thereof shall be extended to the next succeeding Business Day. If the date for any payment under this Agreement is extended, such payment shall bear interest for such extended time at the rate of interest applicable hereunder.

Section 6. Loan Prepayment and Funding Losses ; Overnight Fed Funds Open Rate Funding .

Anything in this Agreement to the contrary notwithstanding, if the Bank determines (which determination shall be binding and conclusive) that quotations of interest rates for the relevant deposits in the definition of Overnight Fed Funds Open Rate in Section 1 are not being provided in the approximate relevant amounts or for the relevant maturities for purposes of determining the rates of interest for Overnight Fed Funds Rate Loans, then the Bank shall give the Borrowers prompt notice thereof, and so long as such condition remains in effect, the Bank shall be under no obligation to make any Loans based on such definition, and the Bank and the Borrowers shall agree forthwith to make Loans based on another mutually acceptable base rate.

Section 7. Evidence of Indebtedness .

(a) The Bank shall maintain in accordance with its usual practice an account or accounts evidencing the indebtedness of the Borrower s to the Bank resulting from each Loan made by the Bank, including the amounts of principal and interest payable and paid to the Bank from time to time. (b) The Bank shall maintain accounts in which it shall record (i) the amount of each Loan made hereunder, (ii) the amount of any principal or interest due and payable or to become due and payable from each Borrower to the Bank hereunder and (iii) the amount of any sum received by the Bank hereunder for the account of the Banks .

(c) T he entries made in the accounts maintained pursuant to subsections (a) and (b) of this Section shall be prima facie evidence of the existence and amounts of the obligations recorded therein; provided that any failure by the Bank to maintain such accounts or ror therein shall not affect the Borrowers obligation to repay the Loans in accordance with the terms of this Agreement.

(d) The Bank may request that Loans made by it be evidenced by a promissory note. In such event, the Borrowers shall prepare, execute and deliver to such Bank a promissory note payable to the order of the Bank (or, if requested by the Bank, to the Bank and its registered assigns) and in a form approved by the Bank. Thereafter, the Loans evidenced by such promissory note and interest thereon shall at all times be represented by one or more promissory notes in such form payable to the order of the payee named therein (or, if such promissory note is a registered note, to such payee and its registered assigns).

Section 8. Representations and Warranties of the Borrowers .

In order to induce the Bank to enter into this Agreement and to extend the Credit Facility to the Borrowers, each Borrower hereby represents and warrants the following to the Bank as of the Agreement Date:

(a) Each Borrower (i) is a corporation duly organized, validly existing and in good standing under the laws of the jurisdiction of its creation, (ii) has all requisite organizational power, authority and legal right to conduct its business as now conducted and as contemplated by its certificate of incorporation and by-laws, to make borrowings hereunder, to execute, deliver and perform this Agreement and to consummate the transactions contemplated hereunder and thereunder, and (iii) is duly qualified to do business and is in good standing in each jurisdiction in which the character of the properties owned or leased by it or in which the transaction of its business makes such qualifications necessary, except that this Section (a)(iii) shall not apply to qualifications the lack of which, singly or in the aggregate, has not had and will not have a Materially Adverse Effect on each Borrower.

(b) E ach Borrower is not in violation of its by-laws or certificate of incorporation or in default in the performance or observance of any material obligation, agreement, covenant or condition contained in any material contract, indenture, mortgage, loan agreement or lease to which each Borrower is a party or by which it may be bound. The execution and delivery of any of this Agreement and the incurrence of the obligations and the consummation of the transactions herein and therein contemplated will not conflict with, or constitute a breach of or default under, certificate of incorporation or by-laws of each Borrower or any material contractual restriction, instrument, indenture, mortgage, agreement or lease to which each Borrower is a party or by which it may be bound, or any law, administrative rule or regulation or court decree.

(c) This Agreement has been duly authorized, executed and delivered by the Borrowers, and constitutes a legal, valid and binding obligation of the Borrowers enforceable in accordance with its terms, except as such enforceability may be limited by applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting the enforcement of creditors' rights generally or by general principles of equity.

(d) No consent, approval, authorization, order, registration or qualification of or with any court, any regulatory authority or other governmental agency or body is required for the execution or delivery of this Agreement by each Borrower or for the consummation of the transactions contemplated by this Agreement.

(e) No Default has occurred and is continuing.

(f) Except as set forth in the SEC Filings, there are no actions, suits, proceedings or investigations pending or, to the knowledge of any of the Borrower, threatened against such Borrower before any court, tribunal, governmental authority or any body or Person with judicial or quasi-judicial authority which has a significant possibility of having a Materially Adverse Effect on any of the Borrowers or its ability to perform under this Agreement.

(g) Each Borrower has filed or caused to be filed all Tax returns required to have been filed and has paid all Taxes shown to be due and payable on such returns or on any assessments made against them (other than those being contested in good faith) and, to the best of each Borrower's knowledge, no Tax Liens have been filed and no claims are being asserted with respect to such Taxes which are not reflected in the financial statements referred to in Section 10(c) hereof, which, if adversely determined, would, in the aggregate, have a Materially Adverse Effect on the value of the total enterprise represented by any of the Borrowers.

(h) No Borrower is an "investment company" within the meaning of the Investment Company Act of 1940, as amended.

(i) Each Borrower is currently in compliance with all Applicable Laws (including, without limitation, ERISA and Environmental Laws), the non-compliance with which would have a Materially Adverse Effect on any Borrower under this Agreement.

(j) No fact or circumstance, to the best of each Borrower's present knowledge, either alone or in conjunction with all other such facts and circumstances, has had or might in the future have (so far as each Borrower can foresee) a Materially Adverse Effect on any Borrower under this Agreement.

Section 9. Conditions Precedent .

(a) The obligation of the Bank to enter into this Credit Agreement and make the initial Loan is subject to satisfaction of the following conditions:

(i) receipt by the Bank in form and substance satisfactory to the Bank of evidence of each B orrower's authority to borrow from the Bank in the form of executed approval of its Board of Directors;

(ii) receipt by the Bank in form and substance satisfactory to the Bank of duly executed originals of this Agreement;

(iii) receipt by the Bank in form and substance satisfactory to the Bank of a secretary's certificate as to the signature and incumbency of the officers of each Borrower executing this Agreement;

(iv) receipt by the Bank in form and substance satisfactory to the Bank of certified copies of the each Borrower's certificate of incorporation and by-laws, together with any amendments thereto.

(b) The making of each Loan (including the initial Loan) shall be subject to the Bank's reasonable determination that each of the following conditions has been fulfilled: (i) the Bank shall have received a notice of borrowing prepared and delivered in accordance with the terms of Section 3 hereof; (ii) the Bank shall have received all applicable documents, information and other items required by this Agreement; (iii) each representation and warranty contained in Section 8 hereof shall be true and correct at and as of the date any Loan is made (except representations and warranties which expressly relate solely to an earlier date or time, which representations and warranties shall be true and correct on and as of the specific dates or times referred to therein); (iv) no Default shall have occurred and be continuing at the time any Loan is to be made; and (v) such Loan shall not contravene any Applicable Law applicable to the Bank.

Section 10. Covenants of the Borrowers .

From the date hereof and until the Credit Facility shall have been terminated or have expired and all amounts due hereunder are paid in full:

(a) Each Borrower shall not consolidate with, merge into, or acquire, any other Person or permit any other Person to consolidate with, merge into, or acquire, it without the prior written consent of the Bank unless (i) any Borrower is the surviving entity, (ii) such Borrower provides the Bank with at least 30 days prior written notice of any such consolidation, merger or acquisition, (iii) based on projections and financial statements prepared in accordance with the accounting standards generally employed in the preparation of each Borrowers financial reports and such other information as the Bank may reasonably request, any such consolidation, merger or acquisition will result in a surviving entity having a "Net Worth" that is equal to or greater than the Net Worth of the such Borrower immediately prior to such consolidation, merger or acquisition and (iv) said surviving entity shall fully assume liability for the performance of all obligations under this Agreement. For the purposes of this Agreement, "Net Worth" shall mean stockholders' equity as determined in accordance with the accounting standards generally employed in the preparation of a Borrower's financial reports.

(b) The Borrower s will not sell, lease, transfer or otherwise dispose of any of its assets, except that this Section 10(b) shall not apply to (i) any disposition of assets, including, but not limited to, the sale of inventory, in the ordinary course of business; (ii) any sale, transfer, lease or other disposition of assets which are no longer necessary or required in the conduct of Borrowers' business as currently conducted or any disposition of obsolete or retired property not

useful to the Borrower s; (iii) any sale, transfer or lease of assets in the ordinary course of business which are replaced by substitute assets acquired or leased; or (iv) any sale, transfer or lease of assets, other than those specifically excepted pursuant to clauses (i) through (iii) above, provided that (A) at the time of any disposition, no Event of Default shall exist or shall result from such disposition, and (B) the aggregate net book value of all assets so sold by the Borrowers shall not exceed in any fiscal year five (5%) of the consolidated total assets of the Borrowers as determined on a consolidated basis in accordance with GAAP.

(c) (i) NJRC shall submit to the Bank, in reasonable detail and within nine ty (9 0) days following the close of each fiscal year of NJRC (or such earlier or later date, from time to time established by the SEC in accordance with the Securities Exchange Act of 1934, as amended), certified copies of the complete annual financial statements of NJRC and its consolidated Subsidiaries, including, but not limited to, the balance sheet and profit and loss statement for such fiscal year including statements of income, retained earnings and cash flows of NJRC for such annual period. The Borrower s will be deemed to have complied with the delivery requirements of this Section 10(c)(i) if within ninety (90) days after the end of their fiscal year (or such earlier or later date, from time to time established by the SEC in accordance with the Securities Exchange Act of 1934, as amended), the Borrowers deliver to the Bank a copy of its Annual Report and Form 10-K as filed with the SEC and the financial statements and certification of public accountants contained therein meets the requirements described in this Section.

(ii) NJRC shall submit to the Bank, in reasonable detail and as soon as available and in any event within forty five (45) days after the close of each fiscal quarter of NJRC (or such earlier or later date, from time to time established by the SEC in accordance with the Securities Exchange Act of 1934, as amended), copies of the complete financial statements of NJRC and its consolidated Subsidiaries, including, but not limited to, the balance sheet and profit and loss statement for such periods including statements of income, retained earnings and cash flows of NJRC for such quarterly period. The Borrowers will be deemed to have complied with the delivery requirements of this Section 10(c)(ii) if within forty-five (45) days after the end of their fiscal quarter (or such earlier or later date, from time to time established by the SEC in accordance with the Securities Exchange Act of 1934, as amended), the Borrowers deliver to the Bank a copy of its Form 10-Q as filed with the SEC and the financial statements contained therein meets the requirements described in this Section.

(iii) Such financial reports shall be prepared in accordance with GAAP applied consistently to all applicable periods, shall present fairly the financial condition of NJRC and its consolidated Subsidiaries and shall be accompanied by a certificate of a duly authorized officer of NJRC stating that he has made or caused to be made a review of NJRC's transactions and condition during the relevant period of NJRC covered by such financial reports and that such review has not disclosed the existence of any event or condition which constitutes a Default or, if any such condition existed or exists, the nature thereof and the action the Borrowers has taken or proposes to take with respect thereto.

(iv) Each Borrower shall submit to the Bank, in reasonable detail and as soon as available, such further information regarding the condition or operations, financial or otherwise, of each Borrower and its Subsidiaries, as the Bank from may time to time reasonably request, provided that such request shall be in connection with required reporting by the Bank to a regulatory agency.

(d) Each Borrower shall (i) preserve and maintain its existence and all of its franchises, licenses, rights and privileges required for the conduct of business, (ii) preserve and maintain insurance with responsible insurance companies against at least such risks and in at least such amounts as it customarily maintained by similar businesses, or as may be required by Applicable Law, (iii) preserve, protect and obtain all intellectual property, and preserve and maintain in good repair, working order and condition all other properties, required for the conduct of its business, (iv) not make any changes in its business activities that have a Materially Adverse Effect on each Borrower (except as otherwise permitted under this Agreement), (v) comply in all material respects with all Applicable Law (including ERISA and Environmental Laws), (vi) pay or discharge when due all Taxes and all Indebtedness that can be reasonably expected to become a Lien on any of its properties, except to the extent that any such Lien is contested in good faith by such Borrower in proper proceedings promptly instituted and diligently pursued to the reasonable satisfaction of the Bank and that such Borrower shall maintain adequate reserves for the satisfaction of such Lien in accordance with generally accepted accounting principles, (vii) not create, assume or incur, or permit or suffer to exist or to be created, assumed or incurred, any Lien (except a Permitted Lien) upon any of its properties or assets of any character, whether now owned or hereafter acquired, or upon any income or profits therefrom, and (viii) take all action and obtain all consents and Governmental Approvals required so that its obligations hereunder will at all times be legal, valid and binding and enforceable in accordance with their respective terms.

(e) If any law, guideline or interpretation or any change in any law, guideline or interpretation or application thereof by any Official Body charged with the interpretation or administration thereof or compliance with any request or directive (whether or not having the force of law) of any central bank or other Official Body:

(i) subjects the Bank to any tax or changes the basis of taxation with respect to this Agreement, the Loans or payments by any Borrower of principal, interest or other amounts due from the Borrowers hereunder (except for taxes on the overall net income of the Bank),

(ii) imposes, modifies or deems applicable any reserve, special deposit or similar requirement against credits or commitments to extend credit extended by, or assets (funded or contingent) of deposits with or for the account of, or other acquisitions of funds by, the Bank or any lending office of the Bank, or

(iii) imposes, modifies or deems applicable any capital adequacy or similar requirement (A) against assets (funded or contingent) of, other credits or commitments to extend credit extended by, the Bank, or (B) otherwise applicable to the obligations of the Bank or any lending office of the Bank under this Agreement,

a e result of any of the foregoing is to increase the cost to, reduce the income receivable by, or impose any expense (including loss of margin) upon the Bank or any lending office of the Bank with respect to this Agreement or the making, maintenance or funding of any part of the Loans (or, in the case of any capital adequacy or similar requirement, to have the effect of reducing the rate of return on the Bank's capital, taking into consideration the Bank's customary policies with respect to capital adequacy) by an amount which the Bank, in its reasonable discretion, deems to be material, the Bank shall from time to time notify the Borrowers of the amount determined in good faith (using any averaging and attribution methods employed in good faith) by the Bank to be necessary to compensate the Bank for such increase in cost, reduction in income, additional expense or reduced rate of return. Such notice shall set forth in reasonable detail the basis for such determination and shall, in the absence of manifest error, be presumed to be correct and binding for all purposes. Such amount shall be due and payable by the Borrowers within thirty (30) Business Days after written demand by the Bank.

(f) Each Borrower covenants and agrees that this Agreement will at all times constitute direct, binding and enforceable obligations of the Borrowers.

(g) Promptly upon becoming aware of the existence of any condition or event which could have a Materially Adverse Effect on, or constitute a default or Default under, this Agreement, the Borrowers will provide written notice to the Bank specifying the nature and period of existence thereof and the action the Borrowers is taking or propose(s) to take with respect thereto.

(h) The Borrowers shall use the proceeds of the Loans only for general corporate purposes including working fund of the Borrowers. None of the proceeds of the Loans shall be used to purchase or carry, or to reduce, retire or refinance any credit incurred to purchase or carry, any margin stock (within the meaning of Regulation U of the Board of Governors of the Federal Reserve System) or to extend credit to others for the purpose of purchasing or carrying any margin stock.

(i) Each Borrower shall ensure that at all times the obligations of the Borrowers hereunder shall constitute unconditional general obligations of the Borrowers ranking in priority of payment at least pari passu with all other unsecured and unsubordinated indebtedness of the Borrowers.

(j) NJRC shall not and shall not permit any Subsidiary of NJRC to change its fiscal year from the twelve-month period beginning October 1 and ending September 30.

(k) Each Borrower shall not at any time permit the ratio of Consolidated Total Indebtedness of the NJRC and its Subsidiaries to Consolidated Total Capitalization to exceed 0.65 to 1.00.

(l) Each Borrower shall not permit the ratio of Consolidated Income from Operations to Consolidated Interest Expense c RC and its Subsidiaries, calculated as of the end of each fiscal quarter for the four fiscal quarters then ended, to be less than 2.50 to 1.00.

(m) NJRC shall submit to the Bank, in form and substance satisfactory to the Bank, at the time of delivery of the financial statements provided for in Section 1 0 (c) above, a certificate of an officer of NJRC , demonstrating compliance with Sections 1 0 (k) and 1 0 (l) hereof as of the close of each fiscal year of NJRC .

Section 11. Events of Default .

If any of the following events (each individually referred to herein as an "Event of Default") shall occur:

(a) any Borrower shall fail to pay in full in the manner provided herein (i) any principal due hereunder, or (ii) any interest or other amount due hereunder within three (3) Business Days after such interest, fee, or other amount becomes due in accordance with the terms hereof; or

(b) any Borrower shall fail to perform, comply with or observe any of its obligations under any of Sections 10(a), 10(b), 10(f), 10(g), 10(h), 10(i), 10(j), 10(k), or 10(l) of this Agreement; or

(c) any Borrower shall fail to perform any of its other obligations under this Agreement and such failure shall not be remedied within thirty (30) Business Days after the occurrence thereof; or

(d) any representation or warranty of any Borrower contained herein or in any certificate or document furnished to the Bank shall prove to be incorrect or misleading in any material respect when made; or

(e) a judicial order shall be made, or an effective resolution passed by the Board of the applicable Borrower, for the winding up of any Borrower, or any Borrower, or any Borrower shall cease to conduct its business in the manner conducted as of the date l f, or any Borrower shall take any steps whatsoever to effect, approve or facilitate any of the foregoing in any way, except as expressly p. itted under the terms of this Agreement; or

(f) any Borrower: (i) shall generally not, or shall be unable to, or shall admit in writing its inability to, pay its debts as such debts mature; or (ii) shall make an assignment for the benefit of its creditors; (iii) shall petition or apply to any tribunal or other body for the appointment of a custodian, receiver, trustee or the like for it or for a substantial part of its assets, whether domestic or foreign; (iv) shall commence any proceeding under any bankruptcy, reorganization, arrangement, readjustment of debt, dissolution or liquidation law or statute of any jurisdiction, whether now or hereafter in effect and whether domestic, international or foreign; (v) shall have had any such petition or application filed or any such proceeding shall have been commenced against it, in which an adjudication or appointment is made or order for relief is entered, and such proceeding shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days or such court shall enter a decree or order granting any of the relief sought in such proceeding; (vi) shall be the subject of any proceeding under which a material portion of its assets may be subject to seizure, forfeiture, or divestiture, and such proceeding shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days or such court shall enter a decree or order granting any of the relief sought in such proceeding; (vii) by any act or omission shall indicate its consent to, approval of, or acquiescence in, any such petition, application, proceeding, order for relief, or appointment of a custodian, receiver, trustee or the like; (viii) shall suffer any such custodianship, receivership, trusteeship, or comparable status and such appointment shall remain undismissed or unstayed and in effect for a period of sixty (60) consecutive days; (ix) shall take any corporate, partnership or other action whatsoever to approve, facilitate or effectuate any of the foregoing in any way; or

(g) any authorization, consent, approval, registration or license now or hereafter necessary to enable the Borrowers to comply with its material obligations hereunder shall expire, be revoked, be withheld or otherwise be ineffective and such expiration, revocation or other ineffectiveness shall continue unremedied for a period of thirty (30) Business Days after an Authorized Officer becomes aware of the occurrence thereof;

(h) (i) either any Borrower or any Subsidiary of the Borrowers shall fail to pay when due and payable (whether at maturity, by acceleration or otherwise, beyond any grace period with respect thereto, whether waived or not) any principal, premium or interest on any Indebtedness and any such failure(s) to pay shall in the aggregate exceed $10,000,000; or (ii) the maturity of any such Indebtedness exceeding $10,000,000 in aggregate shall have been accelerated or have been required to be prepaid prior to the stated maturity date thereof in accordance with the terms of any agreement or instrument evidencing, providing for the creation of, or concerning, such Indebtedness; or

(i) any final judgments or orders for the payment of money in excess of $10,000,000 in the aggregate shall be entered against any Borrower , or any Subsidiary of the Borrowers, and such judgments, or orders are not discharged, vacated, bonded or stayed pending appeal within a period of thirty (30) days from the date of entry provided , however that any such judgment or order shall not been an Event of Default under this Section 11(i) if and so long as (i) the amount of such judgment or order is covered by a valid and binding policy of insurance between the defendant and the insurer covering payment thereof and (ii) such insurer, which

shall be rated at least "A" by A.M Best Company, has been notified of, and has not disputed the claim made for payment of, the amount of such judgment or order ;

(j) any Borrower shall fail to perform under any agreement, lease, mortgage, indenture or other contractual a ement between any Borrower and the Bank or any of its Affiliates such that an amount in excess of $5,000,000 shall remain outstanding past the date on which it was due and payable; or

(k) NJRC shall fail to own, either directly or indirectly and free of any Liens, 100% of the capital stock of the NJRESC ;

THEREUPON, the Bank may, in addition to enforcing all other rights and remedies available to it under Applicable Law or any contract, agreement or instrument, (i) upon notice to the Borrowers, declare the Bank's agreement to make Loans hereunder to be terminated, whereupon the same shall forthwith terminate, and (ii) upon notice to the Borrowers declare all amounts, if any, not otherwise immediately due under this Agreement or in respect of any Loan to be, and all such amounts shall thereupon become, due and payable to the Bank. Upon the occurrence of an Event of Default specified in Section 11(e) or 11(f), automatically and without any notice to the Borrowers, the agreements of the Bank to make Loans hereunder shall be terminated and all amounts, if any, not otherwise immediately due under this Agreement or in respect of any Loan shall be immediately due and payable to the Bank. Presentment, demand, protest or notice of any kind (other than the notice provided for in the immediately preceding sentence) are expressly waived, anything in this Agreement to the contrary notwithstanding. Upon the occurrence of an Event of Default, the Bank shall also have the right to terminate in its sole discretion any and all related swap, swaption, option, cap, collar and other derivative product arrangements of any kind entered into by the Bank in order to provide funding under this Agreement.

Section 12. Illegality .

If, after the date of this Agreement, the adoption of any Applicable Law, any change therein or any change in the interpretation or administration thereof by any government, governmental agency or authority, court, tribunal, central bank or other comparable body charged with the interpretation or administration thereof or compliance by the Bank with any subsequently adopted interpretation, request, guideline or directive (whether or not having the force of law) of any such government, governmental agency or authority, court, tribunal, central bank or other comparable body shall make it unlawful or impossible for the Bank to maintain this Agreement or any Loan, t he Bank shall so notify the Borrowers and no Loans not permitted under Applicable Law shall be made and all outstanding Loans not p itted under Applicable Law shall become due and payable, without premium or penalty, upon the Borrowers' receipt of such notice (or on such earlier or later date as may be required by such Applicable Law, interpretation, guideline, request or directive). Notwithstanding any provision to the contrary set forth in this Section, to the extent permitted under Applicable Law, Loans so

accelerated shall first be converted to Loans bearing interest based on a different rate available hereunder.

Section 13. Governing Law; Submission to Jurisdiction; Waiver of Jury Trial .

This Agreement shall be governed by, and construed in accordance with, the internal laws of the State of New York without regard to conflicts of law principles. Each Borrower irrevocably agrees that any Credit Agreement Related Claim may be brought in any Federal or New York State Court located in the City of New York and, by the execution and delivery of this Agreement, each Borrower hereby irrevocably accepts and submits to the jurisdiction of each of the aforesaid courts in personam , generally and unconditionally, with respect to any such action or proceedings for itself and in respect of its property, assets and revenues. Each Borrower hereby also irrevocably waives, to the fullest extent permitted by law, any objection which it may now or hereafter have to the laying of venue of any such action or proceeding brought in any such court and any claim that any such action or proceeding brought in such court has been brought in an inconvenient forum. Each Borrower further irrevocably consents to service of process out of said courts by mailing a copy thereof, by registered or certified mail, postage prepaid, to itself, and irrevocably waives, to the fullest extent permitted by law, all claim of error by reason of such service in any legal action or proceeding brought in accordance herewith. Each Borrower irrevocably waives, in any legal action or proceeding in any jurisdiction (whether for an injunction, specific performance, damages or otherwise), any right or claim of immunity of any kind with respect to itself or its assets including, without limitation, from attachment or execution of judgment, and each Borrower irrevocably agrees that it and its assets are and shall be subject to any legal action or proceeding, attachment or execution in respect to its obligations under this Agreement. Each Borrower hereby irrevocably agrees that the Bank shall not be liable for, and each Borrower waives and agrees not to seek any special, indirect or consequential damages arising out of any claim related to this Agreement. EACH BORROWER AND THE BANK EACH HEREBY WAIVE TRIAL BY JURY IN ANY JUDICIAL PROCEEDING TO WHICH THEY ARE BOTH PARTIES INVOLVING ANY CREDIT AGREEMENT RELATED CLAIM.

Section 14. Miscellaneous .

(a) Each Borrower shall, on demand, pay or reimburse the Bank for all fees, costs and expenses (including reasonable fees and disbursements of legal counsel and other experts employed or retained by the Bank) incurred, and all payments made, and indemnify and hold the Bank harmless from and against all losses suffered, by the Bank in connection with, arising out of, or in any way related to (i) consulting with respect to any matter in any way arising out of, related to, or connected with this Agreement including (A) the protection, preservation, exercise or enforcement by the Bank of any of its rights under or related to this Agreement or (B) the performance by the Bank of [illegible] its obligations under or related to this Agreement, (ii) protecting, preserving, exercising or enforcing any of the rights of the Bank under o[illegible]ated to this Agreement, (iii) any Credit Agreement Related Claim (whether asserted by the Bank or any Borrower or any other Person and whether asserted before or after the date

hereof), and the prosecution or defense thereof, or (iv) any governmental investigation arising out of, related to, or in any way connected with this Agreement or the relationship established hereunder, except that the foregoing indemnity shall not be applicable to any loss suffered by the Bank to the extent such loss is determined by a judgment of a court referred to in the second sentence Section 13 hereof that is binding on the Borrowers and the Bank, final and not subject to review on appeal, to be the result of acts or omissions on the part of the Bank, constituting (x) willful misconduct or (y) gross negligence

(b) Unless otherwise provided herein, any notice or communication required to be delivered under this Agreement, or any agreement or instrument required to be delivered hereunder (the "Notices") shall be in writing and shall be sent by registered or certified U.S. mail (postage prepaid and return receipt requested), by a reliable hand-delivery or overnight courier service or by telecopier, to be confirmed immediately by sending the original documentation by registered or certified U.S. mail or by a reliable hand-delivery or overnight courier service. Notwithstanding the foregoing sentence, Notices may be given by telephone if confirmed in writing within twenty-four (24) hours by sending a written version thereof by a reliable hand-delivery or overnight courier service. In the event of a discrepancy between any telephonic Notice and any written confirmation thereof, such written confirmation shall be deemed effective notice except to the extent that the Bank has acted in reliance on such telephonic Notice. All Notices shall be delivered or otherwise conveyed to the parties at their respective addresses and telephone and telecopier numbers as follows: (i) if to the Borrowers, at NEW JERSEY RESOURCES CORPORATION, 1415 Wyckoff Road, Wall, New Jersey 07719, Attn. Mr. Glenn C. Lockwood; Telephone: 732-938-1482; Facsimile: 732-905-4328; and, at NJR ENERGY SERVICES COMPANY, 1415 Wyckoff Road, Wall, New Jersey 07719, Attn. Mr. Dennis Veltre; Telephone: 732-938-4541; Facsimile:732-919-8118; (ii) if to the Bank, at Bank of Tokyo-Mitsubishi UFJ Trust Company, 1251 Avenue of the Americas, 12th Floor, New York, New York 10020-1104, Attention: Ms. Mary Coseo, Portfolio Management Group, Telephone: (212) 782-6932, Telecopier: (212) 782-6440, and Mr. Henry Clivilles, Loan Transaction Department, Telephone: (212) 782-4315, Telecopier: (212) 782-6441. Except as otherwise expressly set forth herein, all Notices shall be effective as against the Bank only upon the receipt thereof.

(c) No modification or waiver of any provision of this Agreement, or any other instrument or agreement required hereunder, and no consent to any departure by the Borrowers therefrom, shall in any event be effective unless the same shall be in writing and signed by the parties hereto, and then in each such event such waiver or consent shall be effective only in the specific instance and for the purpose for which given. No notice to or demand on the Borrowers in any case shall, of itself, entitle the Borrowers to any other or further notice or demand in similar or other circumstances.

(d) The terms and provisions of this Agreement shall be binding upon, and the benefits thereof shall inure to, the parties hereto and their respective successors and assigns; provided, however, that any Borrower shall not assign any interest in this Agreement without the prior written consent of

the Borrower's rights, duties, or obligations hereunder or thereunder without the prior written consent of the Bank.

(e) No delay or omission to exercise any right, power, or remedy accruing to the Bank upon any breach or default of any Borrower under this Agreement or any instrument or agreement required hereunder shall impair any such right, power, or remedy of the Bank nor shall it be considered to be a waiver of any such breach or default, or an acquiescence therein, or of or in any similar breach or default thereafter occurring; and no waiver by the Bank of any single breach or default shall be deemed a waiver of any other breach or default theretofore and thereafter occurring. Any waiver, permit, consent, or approval of any kind or character on the part of the Bank of any breach or default under this Agreement or any waiver on the part of the Bank of any provision or condition of this Agreement must be in writing specifically set forth. No remedy herein conferred upon the Bank is intended to be exclusive of any other remedy and each and every such remedy either under this Agreement or by law or otherwise afforded to the Bank, shall be cumulative and not alternative and shall be in addition to every other remedy given hereunder or now or hereafter existing at law or in equity or by statute or otherwise.

(f) Nothing in this Agreement shall be deemed a waiver or prohibition of the Bank's rights of banker's lien or setoff.

(g) This Agreement may be executed in any number of counterparts and on separate counterparts, each of which shall be deemed to be an original and but all of which taken together shall constitute one and the same Agreement.

(h) The Bank may assign, pledge or otherwise transfer any or all of its interests, rights, and/or obligations in, or arising under this Agreement, the Commitment, the Loans and may grant or assign to any person in this Agreement, the Commitment, the Loans with consent from the Borrower, which consent shall not be unreasonably withheld; provided that no such consent is required if (i) an Event of Default exists and is continuing; or (ii) such assignment is to an Affiliate of the Bank with the financial capability and wherewithal to carry out the obligations of the Bank hereunder. Notwithstanding any other provision in this Agreement, the Bank may at any time create a security interest in, or pledge, all or any portion of its rights under and interest in this Agreement and any Term Loan Note held by it in favor of any Federal Reserve Bank in accordance with Regulation A of the FRB or U.S. Treasury Regulation 31 CFR §203.14, and such Federal Reserve Bank may enforce such security interest or pledge in any manner permitted under applicable law.

(i) Unless otherwise specified herein, all accounting determinations hereunder and all computations utilized by the Borrowers in complying with terms used herein shall be interpreted, and all financial statements required to be delivered hereunder shall be prepared, in accordance with the accounting principles set forth in the opinions and pronouncements of the Accounting Principles Board and American Institute of Certified Public Accountants and statements and pronouncements of the Financial Accounting Standards Board.

(j) The Bank hereby notifies the Borrowers that pursuant to the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the "Act"), it is required to obtain, verify and record information that identifies the Borrowers, which information includes the name and address of the Borrowers and other information that will allow the Bank to identify the Borrowers in accordance with the Act.

(k) The term "Borrowers" as used in this Agreement shall, unless otherwise specified in this Agreement, mean the "Borrowers and each of them" and each undertaking and obligation of the Borrowers contained in this Agreement and any other loan documents to which both of the Borrowers are parties shall be their joint and several undertakings and obligations. The Bank may proceed under this Agreement or any other loan documents against either or both of the Borrowers at one time or from time to time, in the sole discretion of the Bank.

[No further text appears on this page]

IN WITNESS WHEREOF , each Borrower and the Bank, acting through their duly authorized representatives, have caused this Credit Agreement to be duly executed in duplicate counterparts in the English language and signed in their respective names the day and year first above written.

NEW JERSEY RESOURCES CORPORATION

By: _____
Name:
Title:

NJR ENERGY SERVICES COMPANY

By: _____
Name:
Title:

BANK OF TOKYO-MITSUBISHI UFJ TRUST COMPANY

By: _____
Name:
Title:

EXHIBIT 21.1

NEW JERSEY RESOURCES CORPORATION

SUBSIDIARIES OF THE REGISTRANT

SUBSIDIARY	STATE OF INCORPORATION
New Jersey Natural Gas Company	New Jersey
NJR Service Corporation	New Jersey
NJR Energy Services Company	New Jersey
Subsidiaries:	
NJR Storage Partners (Limited Partnership)	New Jersey
NJR Capital Services Corporation (f/k/a NJR Development Corp.)	New Jersey
Subsidiaries:	
Commercial Realty & Resources Corp.	New Jersey
NJR Energy Holdings Corporation	New Jersey
Subsidiary:	
NJR Energy Corp.	New Jersey
Subsidiaries:	
NJNR Pipeline Company	New Jersey
NJR Pipeline Company	New Jersey
NJR Investment Company	New Jersey
NJR Retail Holdings Corporation	New Jersey
Subsidiaries:	
NJR Home Services Company	New Jersey
NJR Plumbing Services, Inc.	New Jersey

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

\ nsent to the incorporation by reference in Registration Statement Nos. 33-52409, 333-59013, 333-38808 and 333-133453 on Form S-8 and Registration Statement Nos. 33-57711 and 333-137320 on Form S-3 of our reports dated November 22, 2006, relating to the financial statements and financial statement schedule of New Jersey Resources Corporation (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of Financial Accounting Standards Board interpretation No. 47, Accounting for Conditional Asset Retirement Obligations), and relating to management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of New Jersey Resources Corporation for the year ended September 30, 2006.

/s/ Deloitte and Touche LLP
Parsippany, New Jersey

November 22, 2006

EXHIBIT 31.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Laurence M. Downes, certify that:

1) I have reviewed this Annual Report on Form 10-K of New Jersey Resources Corporation;

2) Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3) Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Annual Report;

4) The Registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-f15(f) and 15d-15(f) for the Registrant and have:

   a.) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

   b.) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c.) evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report based on such evaluation;

   d.) disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to adversely affect, the Registrant's internal control over financial reporting; and

5) The Registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors (or persons performing the equivalent functions):

   a.) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: November 22, 2006

By: /s/ Laurence M. Downes
Laurence M. Downes
Chairman & Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 302
OF THE SARBANES-OXLEY ACT OF 2002

I, Glenn C. Lockwood, certify that:

1) I have reviewed this Annual Report on Form 10-K of New Jersey Resources Corporation;

2) Based on my knowledge, this Annual Report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this Annual Report;

3) Based on my knowledge, the financial statements, and other financial information included in this Annual Report, fairly present in all material respects the financial condition, results of operations and cash flows of the Registrant as of, and for, the periods presented in this Annual Report;

4) The Registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-f15(f) and 15d-15(f) for the Registrant and have:

   a.) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the Registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this Annual Report is being prepared;

   b.) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c.) evaluated the effectiveness of the Registrant's disclosure controls and procedures and presented in this Annual Report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this Annual Report based on such evaluation;

   d.) disclosed in this report any change in the Registrant's internal control over financial reporting that occurred during the Registrant's most recent fiscal quarter that has materially affected, or is reasonably likely to adversely affect, the Registrant's internal control over financial reporting; and

5) The Registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the Registrant's auditors and the audit committee of Registrant's board of directors (or persons performing the equivalent functions):

   a.) all significant deficiencies in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the Registrant's ability to record, process, summarize and report financial information; and

   b.) any fraud, whether or not material, that involves management or other employees who have a significant role in the Registrant's internal control over financial reporting.

Date: November 22, 2006

By: /s/ Glenn C. Lockwood
Glenn C. Lockwood
Senior Vice President,
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF THE CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, Laurence M. Downes hereby certifies as follows:

(a) I am the Chief Executive Officer of New Jersey Resources Corporation (the "Company");

(b) To the best of my knowledge, the Company's Annual Report on Form 10-K for the year ended September 30, 2006 (the "Report") complies in all material respects with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended; and

(c) To the best of my knowledge, based upon a review of the Report, the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

NEW JERSEY RESOURCES CORPORATION

Date: November 22, 2006

By: /s/ Laurence M. Downes
Laurence M. Downes
Chairman & Chief Executive Officer

This certificate accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 or any other provision of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

EXHIBIT 32.2

CERTIFICATION OF THE CHIEF FINANCIAL OFFICER
PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

The undersigned, Glenn C. Lockwood hereby certifies as follows:

(a) I am the Chief Financial Officer of New Jersey Resources Corporation (the "Company");

(b) To the best of my knowledge, the Company's Annual Report on Form 10-K for the year ended September 30, 2006 (the "Report") complies in all material respects with the requirements of Section 13(a) of the Securities Exchange Act of 1934, as amended; and

(c) To the best of my knowledge, based upon a review of the Report, the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

NEW JERSEY RESOURCES CORPORATION

Date: November 22, 2006

By: /s/ Glenn C. Lockwood
Glenn C. Lockwood
Senior Vice President,
Chief Financial Officer

This certificate accompanies this Report pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not be deemed filed by the Company for purposes of Section 18 or any other provision of the Securities Exchange Act of 1934, as amended.

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

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

FORM 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the Fiscal Year Ended September 30, 2006

Commission File Number	*Exact name of registrant as specified in its charter and principal office address and telephone number*	*States of Incorporation*	*I.R.S. Employer I.D. Number*
1-16163	WGL Holdings, Inc. 101 Constitution Ave., N.W. Washington, D.C. 20080 (703) 750-2000	Virginia	52-2210912
0-49807	Washington Gas Light Company 101 Constitution Ave., N.W. Washington, D.C. 20080 (703) 750-4440	District of Columbia and Virginia	53-0162882

Securities registered pursuant to Section 12(b) of the Act (as of September 30, 2006):	
Title of each class	*Name of each exchange on which registered*
WGL Holdings, Inc. common stock, no par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act (as of September 30, 2006):	
Title of each class	*Name of each exchange on which registered*
Washington Gas Light Company preferred stock, cumulative, without par value:	
$4.25 Series	Over-the-counter bulletin board
$4.80 Series	Over-the-counter bulletin board
$5.00 Series	Over-the-counter bulletin board

Indicate by check mark if each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
WGL Holdings, Inc. Yes X No ___
Washington Gas Light Company Yes ___ No X

Indicate by check mark if each registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ___ No X

Indicate by check mark whether each 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 registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes X No ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. X

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
WGL Holdings, Inc. Large Accelerated Filer X Accelerated Filer ___ Non-Accelerated Filer ___
Washington Gas Light Company Large Accelerated Filer ___ Accelerated Filer ___ Non-Accelerated Filer X

Indicate by check mark whether each registrant is a shell company (as defined in Rule 12b-2 of the Act): Yes ___ No X

The aggregate market value of the voting common equity held by non-affiliates of the registrant, WGL Holdings, Inc., amounted to $1,475,648,252 as of March 31, 2006.

WGL Holdings, Inc. common stock, no par value outstanding as of October 31, 2006: 48,885,617 shares.

All of the outstanding shares of common stock ($1 par value) of Washington Gas Light Company were held by WGL Holdings, Inc. as of October 31, 2006.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of WGL Holdings, Inc.'s definitive *Proxy Statement* and Washington Gas Light Company's definitive *Information Statement* in connection with the 2007 Annual Meeting of Shareholders, to be filed with the Securities and Exchange Commission pursuant to Regulation 14A and 14C not later than 120 days after September 30, 2006, are incorporated in Part III of this report.

WGL Holdings, Inc.
Washington Gas Light Company
For the Fiscal Year Ended September 30, 2006

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INTRODUCTION

FILING FORMAT

This Annual Report on Form 10-K is a combined report being filed by two separate registrants: WGL Holdings, Inc. (WGL Holdings) and Washington Gas Light Company (Washington Gas). Except where the content clearly indicates otherwise, any reference in the report to "WGL Holdings," "we," "us" or "our" is to the holding company or the consolidated entity of WGL Holdings and all of its subsidiaries, including Washington Gas which is a distinct registrant that is a wholly owned subsidiary of WGL Holdings.

The *Management's Discussion and Analysis of Financial Condition and Results of Operations* (Management's Discussion) included under Item 7 is divided into the following two major sections:

- **WGL Holdings**—This section describes the financial condition and results of operations of WGL Holdings and its subsidiaries on a consolidated basis. It includes discussions of our regulated and unregulated operations. The majority of WGL Holdings' operations are derived from the results of Washington Gas and, to a much lesser extent, the results of its non-utility operations.
- **Washington Gas**—This section describes the financial condition and results of operations of Washington Gas, a wholly owned subsidiary that comprises the majority of WGL Holdings' regulated utility segment.

Included under Item 8 are Consolidated Financial Statements of WGL Holdings and the Financial Statements of Washington Gas. Also included are the Notes to Consolidated Financial Statements that are presented on a combined basis for both WGL Holdings and Washington Gas.

The Management's Discussion for both WGL Holdings and Washington Gas should be read in conjunction with the respective company's financial statements and the combined Notes to Consolidated Financial Statements.

Unless otherwise noted, earnings per share amounts are presented on a diluted basis, and are based on weighted average common and common equivalent shares outstanding.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

Certain matters discussed in this report, excluding historical information, include forward-looking statements within the meaning of the *Private Securities Litigation Reform Act of 1995* with respect to the outlook for earnings, revenues and other future financial business performance or strategies and expectations. Forward-looking statements are typically identified by words such as, but not limited to, "estimates," "expects," "anticipates," "intends," "believes," "plans," and similar expressions, or future or conditional verbs such as "will," "should," "would" and "could." Although the registrants, WGL Holdings and Washington Gas, believe such forward-looking statements are based on reasonable assumptions, they cannot give assurance that every objective will be achieved. Forward-looking statements speak only as of today, and the registrants assume no duty to update them. The following factors, among others, could cause actual results to differ materially from forward-looking statements or historical performance:

- the level and rate at which costs and expenses are incurred and the extent to which they are allowed to be recovered from customers through the regulatory process in connection with constructing, operating and maintaining the Washington Gas' natural gas distribution system;
- the ability to implement successful approaches to modify the current or future composition of gas delivered to customers or to remediate the effects of the current or future composition of gas delivered to customers, as a result of the introduction of gas from the Dominion Cove Point facility to Washington Gas' natural gas distribution system;
- the ability to recover the costs of implementing steps to accommodate delivery of natural gas to customers as a result of the receipt of gas from the Cove Point facility;
- variations in weather conditions from normal levels;
- the availability of natural gas supply and interstate pipeline transportation and storage capacity;
- the ability of natural gas producers, pipeline gatherers, and natural gas processors to deliver natural gas into interstate pipelines for delivery by those interstate pipelines to the entrance points of Washington Gas' natural gas distribution system as a result of factors beyond our control;

- changes in economic, competitive, political and regulatory conditions and developments;
- changes in capital and energy commodity market conditions;
- changes in credit ratings of debt securities of WGL Holdings or Washington Gas that may affect access to capital or the cost of debt;
- changes in credit market conditions and creditworthiness of customers and suppliers;
- changes in relevant laws and regulations, including tax, environmental and employment laws and regulations;
- legislative, regulatory and judicial mandates or decisions affecting business operations or the timing of recovery of costs and expenses;
- the timing and success of business and product development efforts and technological improvements;
- the pace of deregulation efforts and the availability of other competitive alternatives to our products and services;
- changes in accounting principles;
- acts of God and terrorist activities and
- other uncertainties.

The outcome of negotiations and discussions that the registrants may hold with other parties from time to time regarding utility and energy-related investments and strategic transactions that are both recurring and non-recurring may also affect future performance. All such factors are difficult to predict accurately and are generally beyond the direct control of the registrants. Accordingly, while they believe that the assumptions are reasonable, the registrants cannot ensure that all expectations and objectives will be realized. Readers are urged to use care and consider the risks, uncertainties and other factors that could affect the registrants' business as described in this Annual Report on Form 10-K. All forward-looking statements made in this report rely upon the safe harbor protections provided under the *Private Securities Litigation Reform Act of 1995*.

GLOSSARY OF KEY TERMS

Active Customer Meters: Natural gas meters that are physically connected to a building structure within the Washington Gas distribution system and service is active. Customers are billed for flowing gas and/or fixed charges.

Book Value Per Share: Common shareholders' equity divided by the number of common shares outstanding.

Bundled Service: Service in which customers purchase both the natural gas commodity and the distribution or delivery of the commodity from the local regulated utility. When customers purchase bundled service from Washington Gas, no mark-up is applied to the cost of the natural gas commodity that is passed through to customers. Washington Gas has an opportunity to earn a fair rate of return on the net investment used to deliver natural gas.

City Gate: A point or measuring station at which a gas distribution company such as Washington Gas receives natural gas from an unaffiliated pipeline or transmission system.

Delivery Service: The regulated distribution or delivery of natural gas to retail customers. Washington Gas provides delivery service to retail customers in Washington, D.C. and parts of Maryland and Virginia.

Dividend Yield on Book Value: Dividends declared per share divided by book value per share.

Firm Customers: Customers whose gas supply will not be disrupted to meet the needs of other customers. Typically, this class of customer comprises residential customers and the vast majority of commercial customers.

Gross Margin: Revenues, less the associated cost of energy.

Heating Degree Day (HDD): A measure of the variation in weather based on the extent to which the daily average temperature falls below 65 degrees Fahrenheit.

HVAC: Heating, ventilating and air conditioning products and services.

Interruptible Customers: Large commercial customers whose service can be temporarily interrupted in order for the regulated utility to meet the needs of firm customers. These customers pay a lower delivery rate than firm customers and they must be able to readily substitute an alternate fuel for natural gas.

Market-to-Book Ratio: Market price of a share of common stock divided by its book value per share.

Merchant Function: The purchase of the natural gas commodity by Washington Gas on behalf of retail customers.

New Customer Meters Added: Natural gas meters that are newly connected to a building structure within the Washington Gas distribution system. Service may or may not have been activated.

Payout Ratio: Dividends declared per share divided by basic earnings per share.

PSC of DC: The Public Service Commission of the District of Columbia is a three-member board that regulates Washington Gas' distribution operations in the District of Columbia.

PSC of MD: The Public Service Commission of Maryland is a five-member board that regulates Washington Gas' distribution operations in Maryland.

Regulated Utility Segment: Includes the operations of Washington Gas which are regulated by regulatory commissions located in the District of Columbia, Maryland and Virginia, and the operations of Hampshire Gas Company which are regulated by the Federal Energy Regulatory Commission.

Retail Energy-Marketing: Unregulated sales of natural gas and electricity to end users by our subsidiary, Washington Gas Energy Services, Inc.

Return on Average Common Equity: Net income divided by average common shareholders' equity.

Revenue Normalization Adjustment (RNA): A regulatory billing mechanism designed to stabilize the level of net revenues collected from customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels, and other factors such as conservation. Currently, an RNA is in effect for Maryland customers.

SCC of VA: The State Corporation Commission of Virginia is a three-member board that regulates Washington Gas' distribution operations in Virginia.

Service Area: The region in which Washington Gas operates. The service area includes Washington, D.C., and the surrounding metropolitan areas in Maryland and Virginia.

Tariffs: Documents issued by the regulatory commission in each jurisdiction that set the prices Washington Gas may charge and the practices it must follow when providing utility service to its customers.

Third-Party Marketer: Unregulated companies that sell natural gas and electricity directly to retail customers. Washington Gas Energy Services, Inc., a subsidiary company of Washington Gas Resources Corp., is a third-party marketer.

Therm: A natural gas unit of measurement that includes a standard measure for heating value. We report our natural gas sales and deliveries in therms. A therm of gas contains 100,000 British thermal units of heat, or the energy equivalent of burning approximately 100 cubic feet of natural gas under normal conditions. Ten million therms equal approximately one billion cubic feet of natural gas.

Unbundling: The separation of the delivery of natural gas or electricity from the sale of these commodities and related services that, in the past, were provided only by a regulated utility.

Utility Net Revenues: Utility revenues, less the associated cost of gas and applicable revenue taxes.

Value-At-Risk: A risk measurement that estimates the largest expected loss over a specified period of time under normal market conditions within a specified probabilistic confidence interval.

Washington Gas: Washington Gas Light Company is a subsidiary of WGL Holdings, Inc. that delivers and sells natural gas primarily to retail customers in accordance with tariffs set by the PSC of DC, the PSC of MD and the SCC of VA.

Washington Gas Resources Corporation: Washington Gas Resources Corp. is a subsidiary of WGL Holdings, Inc. that owns the majority of the non-utility subsidiaries.

WGEServices: Washington Gas Energy Services, Inc. is a subsidiary of Washington Gas Resources Corp. that sells natural gas and electricity to retail customers on an unregulated basis.

WGESystems: Washington Gas Energy Systems, Inc., is a subsidiary of Washington Gas Resources Corp. that offers HVAC-related products and services to commercial customers.

WGL Holdings: WGL Holdings, Inc. is a holding company that became the parent company of Washington Gas Light Company and its subsidiaries effective November 1, 2000.

Weather Insurance Policy: An insurance policy that provides protection from the negative financial effects of warmer-than-normal weather during the winter heating season.

Weather Derivative: A financial instrument that provides protection from the negative financial effects of warmer-than-normal weather during the winter heating season.

ITEM 1. BUSINESS

INTRODUCTION

WGL Holdings is a holding company that was established on November 1, 2000. WGL Holdings owns all of the shares of common stock of Washington Gas, a regulated natural gas utility, and all of the shares of common stock of Washington Gas Resources Corporation (Washington Gas Resources), Hampshire Gas Company (Hampshire) and Crab Run Gas Company (Crab Run). Washington Gas Resources owns all of the shares of common stock of various unregulated, energy-related businesses.

WGL Holdings, through its subsidiaries, sells and delivers natural gas, and provides a variety of energy-related products and services to customers primarily in Washington, D.C., and the surrounding metropolitan areas in Maryland and Virginia. Our core subsidiary, Washington Gas, engages in the delivery and sale of natural gas that is regulated by regulatory commissions in the District of Columbia, Maryland and Virginia. Through the wholly owned subsidiaries of Washington Gas Resources, we also offer energy-related products and services.

SUBSIDIARIES

WGL Holdings is the parent of four direct, wholly owned subsidiaries. The following paragraphs describe each subsidiary in the WGL Holdings' corporate structure at September 30, 2006.

Washington Gas—is a regulated public utility that delivers and sells natural gas to customers in Washington, D.C. and adjoining areas in Maryland, Virginia and several cities and towns in the northern Shenandoah Valley of Virginia. Washington Gas has been engaged in the natural gas distribution business for 158 years, since its incorporation by an Act of Congress in 1848. Washington Gas has been a domestic corporation of the Commonwealth of Virginia since 1953, and a corporation of the District of Columbia since 1957. Washington Gas serves over one million customers in an area having a population estimated at five million.

As of September 30, 2006, Washington Gas had 1.032 million active customer meters. Active customer meters reflect all natural gas meters connected to the Washington Gas distribution system, excluding those meters that are not currently receiving service. The following table lists the number of active customer meters and therms delivered by jurisdiction as of and for the year ended September 30, 2006.

Active Customer Meters and Therms Delivered by Jurisdiction

Jurisdiction	Active Customer Meters as of September 30, 2006	Millions of Therms Delivered Fiscal Year Ended September 30, 2006
District of Columbia	150,636	292.9
Maryland	421,216	725.4
Virginia	460,064	558.6
Total	**1,031,916**	**1,576.9**

Of the 1.577 billion therms delivered in fiscal year 2006, 813.8 million therms, or 51.6 percent, were sold and delivered by Washington Gas and 763.1 million therms, or 48.4 percent, were delivered by Washington Gas to various customers that acquired their natural gas from competitive natural gas suppliers described as third-party marketers. Of the total therms delivered, Washington Gas delivered 76.8 percent to firm residential and commercial customers, 16.3 percent to interruptible customers, and the remaining 6.9 percent to customers that use natural gas to generate electricity either under an interruptible or special firm contract.

Washington Gas Resources—owns most of our unregulated subsidiaries. The subsidiaries of Washington Gas Resources, as described below, include Washington Gas Energy Services, Inc. (WGEServices), Washington Gas Energy Systems, Inc. (WGESystems) and Washington Gas Credit Corporation (Credit Corp.). On September 29, 2006, Washington Gas Resources sold all of the outstanding shares of common stock of its wholly owned subsidiary, American Combustion Industries, Inc. (ACI), a full-service mechanical contractor that offered turnkey products and services associated with mechanical heating, ventilating and air conditioning (HVAC) systems. Refer to Note 2 of the Notes to Consolidated Financial Statements for a further discussion of the ACI sale. Effective December 4, 2006, Washington Gas Resources dissolved its wholly owned subsidiary, WG Maritime Plaza I, Inc. (WG Maritime), which held a carried interest in two buildings developed on land owned by Washington Gas. These two buildings were

sold in fiscal year 2004. Refer to the section entitled *Properties* under Item 2 of this Form 10-K for further information related to a development project on this land.

WGEServices—is engaged in the sale of natural gas and electricity to retail customers in competition with other unaffiliated, unregulated marketers. At September 30, 2006, WGEServices served approximately 142,700 residential, commercial and industrial natural gas customers, and 63,300 electricity customers located in Maryland, Virginia, Delaware and the District of Columbia. WGEServices purchases natural gas and electricity for resale and does not own or operate any natural gas or electric generation, production, transmission or distribution assets. Washington Gas delivers most of the natural gas sold by WGEServices. Unaffiliated electric utilities deliver all of the electricity sold by WGEServices.

WGESystems—is a provider of commercial energy services, including the design, construction and renovation of mechanical HVAC systems, electrical distribution systems, control and security systems, energy conservation measures, and alternative energy technologies to institutional and commercial customers in the District of Columbia and parts of Virginia and Maryland.

Credit Corp.—offered financing to customers to purchase gas appliances and other energy-related equipment. This business no longer offers new loans, but continues to service its existing loan portfolio. Substantially all of this loan portfolio has been amortized and, therefore, is not material.

Hampshire—is a regulated utility that operates an underground natural gas storage facility in Hampshire County, West Virginia. Washington Gas purchases all of the storage services of Hampshire. Washington Gas includes the cost of these services in the bills sent to its customers. Hampshire is regulated under a cost of service tariff by the Federal Energy Regulatory Commission (FERC).

Crab Run—is an exploration and production company whose assets are managed by an Oklahoma-based limited partnership in which Crab Run is a limited partner. At September 30, 2006, Crab Run's investment in this partnership was not material. WGL Holdings' investment in this subsidiary also is not material, and we expect that future investments in Crab Run will be minimal.

INDUSTRY SEGMENTS

Through our subsidiaries, as described above, we have three operating segments: 1) regulated utility; 2) retail energy-marketing and 3) commercial HVAC products and services. These three segments are described below. Transactions not specifically identifiable in one of these three segments are accumulated and reported in the category "Other Activities."

Regulated Utility

With approximately 92 percent of our consolidated total assets, the regulated utility segment consists of Washington Gas and Hampshire. Washington Gas delivers natural gas to retail customers in accordance with tariffs approved by the regulatory commissions that have jurisdiction over Washington Gas' rates. Washington Gas also sells natural gas to customers who have not elected to purchase natural gas from unregulated third-party marketers. Washington Gas does not earn a profit or incur a loss when it sells the natural gas commodity because utility customers are charged for the natural gas commodity at the same cost that Washington Gas incurs. At September 30, 2006, Washington Gas was selling and delivering the natural gas commodity to 85.7 percent of its customers. The remaining 14.3 percent of Washington Gas' customers utilized the delivery services of Washington Gas for delivery of the natural gas commodity purchased from unregulated third-party marketers, such as WGEServices.

Hampshire, regulated by the FERC, is also part of our regulated utility segment. Hampshire operates an underground natural gas storage facility that provides services exclusively to Washington Gas. Hampshire operates under a "pass-through" cost of service-based tariff approved by the FERC, and adjusts its billing rates to Washington Gas on a periodic basis to account for changes in its investment in utility plant and associated expenses.

During fiscal years ended September 30, 2006, 2005 and 2004, the regulated utility segment reported total operating revenues of $1.6 billion, $1.4 billion and $1.3 billion, respectively, representing 62.1 percent, 64.8 percent and 62.6 percent, respectively, of consolidated total operating revenues.

Factors critical to the success of the regulated utility segment include: *(i)* operating a safe and reliable natural gas distribution system; *(ii)* having sufficient natural gas supplies to serve the demand of its customers; *(iii)* being competitive with other sources of energy such as electricity, fuel oil and propane and *(iv)* recovering the costs and expenses of this business in the rates it charges to customers.

Retail Energy-Marketing

The retail energy-marketing segment includes the operations of our WGEServices subsidiary which competes with other unregulated third-party marketers by selling natural gas and electricity directly to residential, commercial and industrial customers. WGEServices buys and resells natural gas and electricity with the objective of earning a profit through competitively-priced contracts. These commodities are delivered to retail customers through the assets owned by regulated utilities, such as Washington Gas or other unaffiliated natural gas or electric utilities.

Factors critical to the success of the retail energy-marketing segment include: *(i)* managing the market risk of the difference between the sales price committed to customers under sales contracts and the cost of natural gas and electricity needed to satisfy these sales commitments; *(ii)* managing credit risks associated with customers of and suppliers to this segment; *(iii)* having sufficient deliverability of natural gas and electric supplies and transportation to serve the demand of its customers which can be affected by the ability of natural gas producers, pipeline gatherers, natural gas processors, interstate pipelines, suppliers of electricity and regional electric transmission operators to deliver the respective commodities and *(iv)* controlling the level of selling, general and administrative expenses, including customer acquisition expenses.

Commercial HVAC

The commercial HVAC segment includes the operations of our WGESystems subsidiary which manages design-build and renovation projects and provides maintenance services to the commercial and government markets. There are many competitors in this business segment. WGESystems focuses on retrofitting the mechanical, electrical and energy-related systems of a large number of aging commercial and government structures, primarily in the District of Columbia and portions of Maryland and Virginia. Factors critical to the success of the commercial HVAC segment include: *(i)* generating adequate revenue from the government and private sectors in the facility construction and retrofit markets; *(ii)* building a stable base of customer relationships; *(iii)* estimating and managing fixed-price contracts and *(iv)* controlling selling, general and administrative expenses.

For a further discussion of segment financial results, see Note 17 of the Notes to Consolidated Financial Statements.

RATES AND REGULATORY MATTERS

Washington Gas is regulated by the Public Service Commission of the District of Columbia (PSC of DC), the Public Service Commission of Maryland (PSC of MD) and the State Corporation Commission of Virginia (SCC of VA). The following section, "*General Regulatory Matters,*" is a discussion of Washington Gas' general regulatory issues, and the section entitled "*Jurisdictional Rates and Regulatory Matters*" is a discussion of information regarding each commission and recent regulatory proceedings.

General Regulatory Matters

For the majority of its business, Washington Gas charges its customers a price based on the combination of the cost it incurs for the natural gas commodity, including charges for interstate pipeline services, and a charge for delivering natural gas to its customers (also refer to the section below entitled "*Natural Gas Unbundling*"). In all jurisdictions, the cost of the natural gas commodity and the charge for the delivery service are determined as separate components of customers' bills. The charge for the delivery service component of customers' bills varies based on the type of service being provided, such as for firm or interruptible service.

Regulated Service to Firm Customers. In the District of Columbia jurisdiction, the rate schedules for firm delivery service are based upon: *(i)* a flat volumetric charge for the delivery of each therm of natural gas consumed and *(ii)* a fixed customer charge designed to recover certain fixed costs associated with maintaining facilities located on the customer's property, as well as certain other costs that do not vary with the amount of natural gas consumed by customers. Non-residential firm customers in the District of Columbia also pay a peak-usage charge designed to recover the cost to serve customers during peak periods. In the Maryland and Virginia jurisdictions, the rate schedules for firm delivery service are composed of: *(i)* a fixed charge per customer and *(ii)* a variable volumetric rate structured as a declining rate based on increasing blocks of volumes. Declining block rates have the effect of minimizing fluctuations in revenues that otherwise would result from deviations from normal weather. Effective October 1, 2005, rate schedules in the Maryland jurisdiction also reflect the effects of a new billing mechanism (refer to the section entitled *"Jurisdictional Rates and Regulatory Matters—Maryland Jurisdiction"*).

The tariff provisions for firm sales service customers in each Washington Gas jurisdiction contain gas cost recovery mechanisms. These mechanisms provide for the recovery of the invoice cost of natural gas, including the cost to store and transport the gas commodity to Washington Gas' city gate, applicable to firm customers. Under these mechanisms, firm customer rates are adjusted

periodically to reflect increases and decreases in the actual cost of gas. Moreover, provisions in each jurisdiction provide for an annual reconciliation of gas costs collected from firm customers to the applicable invoice cost of gas paid to natural gas suppliers, as well as the invoice cost of storage and transportation paid to pipeline companies, on behalf of these customers. Differences between the amount collected from customers and what is paid to suppliers for natural gas are collected from or refunded to customers over subsequent periods. Washington Gas receives from or pays to its customers in the District of Columbia and Virginia, at short-term interest rates, carrying costs associated with under- or over-collected gas costs recovered from its customers.

Regulated Service to Interruptible Customers. Interruptible service is primarily a delivery service to certain qualified customers where the delivery can be "interrupted" under certain conditions. A limited number of interruptible customers in the District of Columbia and Virginia elect to receive a service which includes the sale of the natural gas commodity and the delivery of that commodity. To qualify for interruptible service, customers must be capable of either substituting an alternate fuel for natural gas or operating without utilizing natural gas should Washington Gas determine that it must interrupt service temporarily to meet firm customers' needs during periods of peak demand. The effect on net income of any changes in delivered volumes and prices to interruptible customers is limited by margin-sharing arrangements that are included in Washington Gas' rate designs in the District of Columbia and, to a much smaller extent, in Virginia. In the District of Columbia, Washington Gas shares a majority of the margins earned on interruptible gas sales and deliveries with firm customers after a gross margin threshold is reached. A portion of the fixed costs for servicing interruptible customers is collected through the firm customers' rate design. In the Virginia jurisdiction, rates for customers using interruptible delivery service are based on a traditional cost of service approach, and Washington Gas retains all revenues from interruptible delivery service. However, a few customers have been grandfathered into a bundled sales and delivery service with previously approved bundled interruptible rate design. A portion of these revenues is shared with firm customers, but the volumes are small and the amounts of revenues are not material to our consolidated results of operations. Prior to October 1, 2005, interruptible customers in the Maryland jurisdiction had similar margin-sharing arrangements for interruptible customers in the District of Columbia, as described above. Effective October 1, 2005, pursuant to Washington Gas' implementation of a new billing mechanism in the Maryland jurisdiction, rates for interruptible customers in Maryland are based on a traditional cost of service approach, and Washington Gas retains a defined amount above a pre-approved margin threshold level (refer to the section entitled *"Jurisdictional Rates and Regulatory Matters—Maryland Jurisdiction"*).

Natural Gas Unbundling. As discussed above, although most of Washington Gas' revenue is generated from the sale and delivery of natural gas on a combined or "bundled" basis, federal and state regulation allows for the separation or "unbundling" of the sale of the natural gas commodity from the delivery of natural gas on Washington Gas' distribution system (delivery service). Gross margins generated by Washington Gas from deliveries of customer-owned gas are equivalent to those earned on bundled gas service because it is only allowed to charge its customers the cost it pays for the natural gas commodity and related charges for interstate pipeline services. Therefore, Washington Gas does not experience any economic loss when customers choose to purchase the natural gas commodity from unregulated third-party marketers.

Throughout the Washington Gas service area, all customers may choose to purchase natural gas from a variety of unregulated third-party marketers, including WGEServices, an affiliated natural gas and electricity retail marketer. When customers select an unregulated third-party marketer as their gas supplier, Washington Gas continues to charge these customers to deliver natural gas through its distribution system at rates identical to the delivery portion of the bundled sales service customers. The status of the unbundling programs in Washington Gas' major jurisdictions as of September 30, 2006 is discussed further in the section entitled *"Competition."*

WGEServices sells natural gas, as an unregulated third-party marketer, to both firm and interruptible customers in each Washington Gas jurisdiction. Washington Gas provides delivery service for those customers of WGEServices that reside in its jurisdiction. In addition, WGEServices sells to Delaware and other areas in Maryland and Virginia that are outside of Washington Gas' jurisdictional service area.

Jurisdictional Rates and Regulatory Matters

A description of each commission under which Washington Gas is regulated and a discussion of significant regulatory matters in each jurisdiction are presented below. Also see the section entitled *"Regulatory Matters"* in Management's Discussion for a table that summarizes Washington Gas' major rate applications and results.

District of Columbia Jurisdiction

The PSC of DC consists of three full-time members who are appointed by the Mayor with the advice and consent of the District of Columbia City Council. The term of each commissioner is four years. There are no limitations on the number of terms that can be served. The PSC of DC has no required period of time by which it must make decisions for modifications to base rates charged by Washington Gas to its customers.

Rate Case and Other Regulatory Activities

On May 1, 2006, Washington Gas filed two tariff applications with the PSC of DC requesting approval of proposed revisions to the balancing charge provisions of its firm and interruptible delivery service tariffs that would permit the utility to recover from its delivery service customers the costs of hexane (heavy hydrocarbons or "HHCs") that are being injected into Washington Gas' natural gas distribution system. Washington Gas has been recovering the costs of HHCs from sales customers in the District of Columbia through its Purchased Gas Charge (PGC) provision in this jurisdiction. On October 2, 2006, the PSC of DC issued an order rejecting Washington Gas' proposed tariff revisions until the PSC of MD concludes on its evidentiary hearing related to this matter which is scheduled to be held on February 6, 2007 (refer to *"Maryland Jurisdiction"* below). On October 12, 2006, Washington Gas filed a Motion for Clarification requesting that the PSC of DC affirm that Washington Gas can continue collecting HHC costs from sales customers through its PGC provision or to record such HHC costs incurred as a regulatory asset pending a ruling by the PSC of DC on future cost recovery. Pending the PSC of DC's decision on the Motion for Clarification, Washington Gas continues to recover the costs of HHCs from sales customers in the District of Columbia through its PGC provision, and is recording these costs as a regulatory asset.

Maryland Jurisdiction

The PSC of MD currently consists of four full-time members who are appointed by the Governor with the advice and consent of the Senate of Maryland; a fifth PSC of MD seat currently is vacant. Each commissioner is appointed to a five-year term, with no limit on the number of terms that can be served.

Washington Gas is required to give 30 days' notice before filing for a rate increase. The PSC of MD may initially suspend the proposed increase for 150 days following the 30-day notice period, and then has the option to extend the suspension for an additional 30 days. If action has not been taken after 210 days, the requested rates become effective subject to refund.

Rate Case and Other Regulatory Activities

Accounting Order. On April 28, 2005, Washington Gas filed a request for an Accounting Order with the PSC of MD in connection with a rehabilitation project being performed in a portion of Prince George's County, Maryland to address an increase in natural gas leaks (refer to the section entitled *"Operating Issues in Prince George's County, Maryland"*). In this filing, Washington Gas requested that the PSC of MD issue an Accounting Order to ratify Washington Gas' interpretation of the applicable regulatory guidelines regarding the accounting treatment of a portion of the cost of the rehabilitation project. Specifically, Washington Gas interpreted the guidelines to require it to record the estimated $13 million cost to encapsulate couplings on mains in the affected areas of Prince George's County as a capital expenditure. After considering this matter at the June 1, 2005 Administrative Meeting of the PSC of MD, the PSC of MD granted Washington Gas' request for an Accounting Order with the understanding that the accounting treatment will not be determinative of future ratemaking treatment, and the PSC of MD retains jurisdiction to adopt any ratemaking treatment it deems appropriate.

Interruptible Transportation Service and RNA Mechanism. On August 8, 2005, the PSC of MD approved an unopposed Stipulation and Agreement (Stipulation) that was previously filed with the PSC of MD by Washington Gas and three other participants. The Stipulation resolved outstanding issues from an October 31, 2003 Final Order issued by the PSC of MD regarding the manner in which interruptible transportation service is charged to Maryland customers (refer to the section above entitled *"Regulated Service to Interruptible Customers"* for a discussion of this service). As proposed in the Stipulation, the PSC of MD also approved Washington Gas' implementation of a new billing mechanism known as the Revenue Normalization Adjustment (RNA). The RNA mechanism is designed to stabilize the level of utility net revenues collected from Maryland customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels and other factors such as conservation. The Stipulation also allows for the impact of the RNA mechanism on Washington Gas' risk and rate of return to be evaluated in the next rate case. The RNA became effective on October 1, 2005. Washington Gas' net income for the fiscal year ended September 30, 2006 reflects the effect of the RNA.

Disallowance of Purchased Gas Charges. Washington Gas submitted to a routine review of its gas costs that were billed to customers in Maryland from September 2003 through August 2004. Each year, the PSC of MD reviews the annual gas costs collected from customers to determine if Washington Gas' purchased gas costs are not justified because it failed to support that the charges incurred were based solely on increased costs of natural gas, or it failed to follow competitive and reasonable practices in procuring and purchasing natural gas. On March 14, 2006, a Hearing Examiner of the PSC of MD issued a proposed order approving purchased gas charges of Washington Gas for the twelve-month period ending August 2004, except for $4.6 million of such charges that the Hearing Examiner recommended be disallowed because, in the opinion of the Hearing Examiner, they were not reasonably and prudently incurred. Washington Gas filed a Notice of Appeal on April 12, 2006 and a Memorandum on Appeal on April 21, 2006 with the PSC of MD, asserting that the Hearing Examiner's recommendation is without merit. A reply memorandum was filed on May 11, 2006. After consideration of these issues, we expect the PSC of MD to issue a Final Order. Over the past ten years, Washington Gas has incurred similar purchased gas charges which the PSC of MD has reviewed and approved as being reasonably and prudently incurred and therefore subject to recovery from customers. Among other issues included in the appeal, we reminded the PSC of MD of this prior recovery and requested that similar treatment be granted for this matter. During the fiscal year ended September 30, 2006, Washington Gas accrued a liability of $4.6 million (pre-tax) related to the proposed disallowance of these purchased gas charges. If the PSC of MD rules in Washington Gas' favor, the liability recorded in the 2006 fiscal year for this issue will be reversed.

Recovery of Hexane costs. In March 2006, Washington Gas began recovering the costs of HHCs that are being injected into its natural gas distribution system from Maryland sales customers through its PGC provision in Maryland. On April 28, 2006, Washington Gas filed an application with the PSC of MD requesting approval of proposed revisions to the balancing charge provisions of its firm and interruptible delivery service tariffs that would permit the utility to recover the cost of HHCs from its delivery service customers, as well as from its sales customers. On June 27, 2006, the PSC of MD issued an order that rejected Washington Gas' proposed tariff revisions until an evidentiary hearing is held to further consider matters relating to the efficacy of the HHC injections in addressing existing leaks or in preventing additional leaks on Washington Gas' distribution system (refer to the section entitled *"Operating Issues in Prince George's County, Maryland"*). In addition to ordering an evidentiary hearing, the PSC of MD directed Washington Gas to cease recovering HHC costs being recovered through the PGC provision, and to record costs that will be incurred in the future in a "pending" account for future regulatory disposition following the conclusion of the evidentiary hearing. The PSC of MD also indicated that the disposition of HHC costs collected previously through the PGC provision will be determined in the course of the evidentiary hearing which is scheduled to be held on February 6, 2007.

Virginia Jurisdiction

The SCC of VA consists of three full-time members who are elected by the General Assembly of Virginia. Each commissioner has a six-year term with no limitation on the number of terms that can be served.

Either of two methods may be used to request a modification of existing rates. First, Washington Gas may file an application for a general rate increase in which it may propose new adjustments to the cost of service that are different from those previously approved for Washington Gas by the SCC of VA, as well as a revised return on equity. The proposed rates under this process may take effect 150 days after the filing, subject to refund pending the outcome of the SCC of VA's action on the application. Second, an expedited rate case procedure is available which provides that proposed rate increases may be effective 30 days after the filing date, also subject to refund. Under the expedited rate case procedure, Washington Gas may not propose any new adjustments for issues not previously approved in its last general rate case, or a change in its return on common equity from the level authorized in its last general rate case. Once filed, other parties may propose new adjustments or a change in the cost of capital from the level authorized in its last general rate case. The expedited rate case procedure may not be available if the SCC of VA decides that there has been a substantial change in circumstances since the last general rate case filed by Washington Gas.

Rate Case and Other Regulatory Activities

Annual Earnings Test. On December 18, 2003, the SCC of VA issued a Final Order in response to an application filed by Washington Gas on June 14, 2002 to increase annual revenues in Virginia. In connection with this Final Order, the SCC of VA ordered Washington Gas to reduce its rate base related to net utility plant by $28 million, which is net of accumulated deferred income taxes of $14 million, and to establish an equivalent regulatory asset that Washington Gas has done for regulatory accounting purposes only. This regulatory asset, which is presented within "Accumulated depreciation and amortization" on the balance sheets, represents the difference between the accumulated reserve for depreciation recorded on the books of Washington Gas and a theoretical reserve that was derived by the Staff of the SCC of VA (VA Staff) as part of its review of Washington Gas' depreciation

rates, less accumulated deferred income taxes. This regulatory asset is being amortized as a component of depreciation expense over 32 years pursuant to the Final Order. The SCC of VA provided for both a return on, and a return of, this regulatory asset established for regulatory accounting purposes.

In approving the treatment described in the preceding paragraph, the SCC of VA further ordered that an annual "earnings test" be performed to determine if Washington Gas has earned in excess of its allowed rate of return on common equity for its Virginia operations. The current procedure for performing this earnings test does not normalize the actual return on equity for the effect of weather over the applicable twelve-month period. To the extent that Washington Gas earns in excess of its allowed return on equity in any annual earnings test period, Washington Gas is required to increase depreciation expense (after considering the impact of income tax benefits), and increase the accumulated reserve for depreciation for the amount of the actual earnings in excess of the earnings produced by a 10.50 percent allowed return on equity. Under the SCC of VA's requirements for performing earnings tests, if weather is warmer than normal in a particular annual earnings test period, Washington Gas is not allowed to restore any amount of earnings previously eliminated as a result of this earnings test. These annual earnings tests will be performed until the $28 million difference between the accumulated reserve for depreciation recorded on Washington Gas' books and the theoretical reserve derived by the VA Staff, net of accumulated deferred income taxes, is eliminated or the level of the regulatory asset established for regulatory accounting purposes is adjusted as a result of a future depreciation study.

In accordance with a September 27, 2004 SCC of VA-approved stipulation involving Washington Gas and other participants, as discussed below, Washington Gas is required to file with the SCC of VA annual earnings test calculations based on a twelve-month period ended December 31. These annual calculations are being estimated by Washington Gas quarterly, and when appropriate, accounting adjustments are being recorded.

On April 27, 2006, Washington Gas filed an earnings test for the twelve months ended December 31, 2005. Washington Gas' filing, which is subject to review by the applicable parties within the SCC of VA, indicated that it had not earned in excess of its allowed return on equity during the period of the earnings test. As discussed below, Washington Gas filed a general rate case application with the SCC of VA on September 15, 2006. The earnings test for the twelve-month period ended December 31, 2005 will be reviewed by the VA Staff in connection with its review of the September 15, 2006 rate application.

Expedited Rate Case and Stipulation. On January 27, 2004, Washington Gas filed an expedited rate case with the SCC of VA to increase annual revenues in Virginia by $19.6 million. On February 26, 2004, based upon expedited rate case filing procedures, Washington Gas placed the proposed revenue increase into effect, subject to refund, pending the SCC of VA's final decision in the proceeding.

On September 27, 2004, the SCC of VA issued a Final Order approving a proposed stipulation of six participants in the rate case that included Washington Gas and the VA Staff. The approved stipulation, among other things, included no change in Washington Gas' annual base revenues, and maintained Washington Gas' allowed rate of return on common equity of 10.50 percent and overall rate of return of 8.44 percent that had been previously approved by a December 18, 2003 Final Order. Washington Gas had recorded a provision for rate refunds equal to the full amount of revenues that had been collected subject to refund through the fiscal year ended September 30, 2004. Accordingly, there was no effect on earnings for fiscal year 2004 for the rates initially put into effect in February 2004. As discussed above, the stipulation also requires Washington Gas to file with the SCC of VA annual earnings test calculations based on a twelve-month period ended December 31.

Application for Rate Increase. On September 15, 2006, Washington Gas filed an application with the SCC of VA to increase its annual utility net revenues in Virginia by approximately $23.0 million. The application seeks an overall rate of return of 9.12 percent and a return on common equity of 11.25 percent. This compares to the current overall rate of return of 8.44 percent and return on common equity of 10.50 percent as authorized by the SCC of VA in its Final Order issued to Washington Gas on December 18, 2003.

In the filed application, Washington Gas also seeks approval of various billing, rate design and other proposals, including: *(i)* the implementation of a billing adjustment mechanism to stabilize the level of revenue collections; *(ii)* the implementation of a Performance-Based Rate (PBR) plan; *(iii)* the recovery of its costs of HHCs as a gas cost from both sales and delivery service customers and *(iv)* the implementation of a Gas Administrative Charge (GAC). Following is a discussion of these proposals.

Washington Gas proposes to implement an RNA billing mechanism in Virginia similar to the mechanism that was implemented in the Maryland jurisdiction. The proposed RNA in Virginia would be designed to stabilize the level of utility net revenues collected from customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels and other factors such as customer conservation.

The Virginia application also proposes a PBR plan that is designed to benefit customers through the incentives given Washington Gas to improve its performance while preserving service quality and the reliability and safety of its natural gas distribution system. The key features of the proposed PBR plan are: *(i)* a three-year freeze of base rates; *(ii)* identified key service quality standards to be upheld by Washington Gas while striving to control operating costs and *(iii)* an earnings sharing mechanism that would enable Washington Gas to share with both its Virginia customers and shareholders earnings in excess of the top of the range of its return on equity.

Washington Gas has incurred costs for the purchase of HHCs that are being injected into its natural gas distribution system to condition natural gas deliveries from a liquefied natural gas (LNG) terminal in Cove Point, Maryland. Consistent with its method of recovering the cost of the natural gas commodity in all jurisdictions, Washington Gas requests authorization by the SCC of VA to recover its costs of HHCs from both sales and unbundled delivery service customers.

Washington Gas also proposes to implement a GAC that would remove the cost of uncollectible account expense related to gas costs from base rates of both firm sales and delivery service customers, and collect an amount through its PGC provision in Virginia for such costs. Similar to the GAC utilized in the Maryland jurisdiction, this mechanism would more appropriately enable the recovery of such costs only from sales customers and the matching of this expense with changes in gas costs.

In its rate application with the SCC of VA, Washington Gas requests that it be permitted to implement the newly proposed increase in revenues, subject to refund, effective for services rendered on and after February 13, 2007. Washington Gas requests that it be permitted to implement other proposed tariff revisions, such as the RNA billing mechanism and PBR plan, upon final approval by the SCC of VA.

The SCC of VA has adopted a procedural schedule that directs the VA Staff and any third parties to file testimony and supporting exhibits during the first quarter of 2007 and sets the hearing date on this matter for April 23, 2007.

Depreciation Study

In October 2006, Washington Gas completed a depreciation rate study based on its property, plant and equipment balances at December 31, 2005. The results of the depreciation study indicate that Washington Gas' depreciation rates should be reduced due to asset lives being extended beyond previously estimated lives. Under regulatory requirements, these depreciation rates must be approved before they are placed into effect.

In Maryland and the District of Columbia, regulatory requirements prescribe that whenever depreciation rates are revised, there must be a corresponding revision to customer billing rates. Accordingly, the new depreciation rates in Maryland and the District of Columbia will not be placed into effect until a rate case proposal is approved enabling this change.

In connection with Washington Gas' September 15, 2006 rate application with the SCC of VA, on November 8, 2006, Washington Gas filed with the SCC of VA that portion of the depreciation study related to the Virginia jurisdiction. Based on the results of the depreciation study, Washington Gas reduced the requested $23.0 million rate increase in the September 15, 2006 SCC of VA application by $5.8 million. Concurrent with the filing of the depreciation study, Washington Gas filed supplemental testimony and schedules reflecting the revised proposed base rate increase of $17.2 million. Consistent with regulatory precedent, Washington Gas expects to implement the changes in recorded depreciation, retroactive to January 1, 2006, upon approval from the VA Staff which is expected in fiscal year 2007.

UTILITY GAS SUPPLY AND PIPELINE TRANSPORTATION AND STORAGE CAPACITY

Supply and Capacity Requirements

Washington Gas arranges to have natural gas delivered to the entry points of its distribution system (city gates or gate stations) using the delivery capacity of interstate pipeline companies, and also uses on-system peaking facilities to meet requirements. To provide the greatest amount of flexibility in meeting its customers' diverse demand requirements, Washington Gas acquires interstate pipeline natural gas delivery and storage capacity on a system-wide basis using different interstate pipelines. Washington Gas' supply and capacity plan is based on forecasted system requirements, and takes into account estimated load growth by type of customer, attrition, conservation, demand by gate station, interstate pipeline and storage capacity and contractual limitations and the forecasted movement of customers between sales service and delivery service.

At September 30, 2006, Washington Gas had service agreements with four pipeline companies that provided firm transportation and/or storage services directly to Washington Gas' city gate. These contracts have expiration dates ranging from fiscal years 2007 to 2028.

Washington Gas is responsible for acquiring both sufficient natural gas supplies and interstate pipeline and storage capacity to meet customer requirements. As such, Washington Gas must contract for reliable and adequate delivery capacity to its distribution system, while considering the dynamics of the interstate pipeline and storage capacity market, its own on-system natural gas peaking facilities, as well as the characteristics of its customer base. Washington Gas' contracting activities take into account customers' tendencies to switch between sales and delivery service; however, short-term contractual arrangements required to manage such customer choice diversity may not be available in future periods under conditions of capacity constraints.

Washington Gas has adopted a diversified portfolio approach designed to satisfy the supply and deliverability requirements of its customers, using multiple supply points, dependable interstate pipeline transportation and storage arrangements, and its own substantial storage and peaking capabilities to meet its customers' demands. Washington Gas anticipates enhancing its peaking capacity by constructing an LNG peaking facility that is currently expected to be completed and placed in service by the 2011-2012 winter heating season. This represents a delay from the originally planned completion date, which was expected by the 2008-2009 winter heating season, due to zoning and other legal challenges. On November 8, 2006, the District Council of Prince George's County issued a final decision denying Washington Gas' application related to its proposed construction of the LNG peaking plant. The District Council held that current zoning restrictions prohibit such construction. Washington Gas appealed this decision to the Prince George's County Circuit Court on November 22, 2006. Until such time when these legal challenges are resolved and the LNG plant is built, Washington Gas has planned for alternative sources of supply to meet its customers' peak day requirements. These planned alternatives, that are expected to be completed by fiscal year 2011, include acquiring additional interstate pipeline capacity, in combination with investments by Washington Gas to upgrade the infrastructure of its transmission and distribution system. This plan is expected to provide for sufficient delivery of natural gas to meet customers' peak day demand requirements until the new LNG storage facility is constructed and in service (refer to the section entitled *"Liquidity and Capital Resources—Capital Expenditures"* in Management's Discussion included under Item 7 of this report for a further discussion of this construction project).

Local distribution companies, such as Washington Gas, along with other participants in the energy industry have raised concerns regarding the gradual depletion in the availability of additional interstate pipeline and storage capacity. Depleting pipeline and storage capacity is a business issue that must be managed by Washington Gas, whose customer base has grown at an annual rate of approximately two percent. This rate of growth is expected to continue. The increase in the near future in the number of electric generation facilities that are fueled by natural gas for the mid-Atlantic region and upstream of the mid-Atlantic region exacerbates concerns associated with the availability of pipeline and storage capacity. These facilities, which utilize significant pipeline and storage capacity, may ultimately affect deliverability and flexibility of natural gas delivery into the region. Due to the reluctance on the part of both marketers and some local distribution companies in committing to long-term pipeline contracts, pipeline infrastructure improvements have been limited despite the fact that the major pipelines serving the Washington Gas system are fully subscribed. In response to demand, interstate pipelines are offering infrastructure improvements that will expand pipeline and storage capacity in the mid-Atlantic region. These improvement projects, funded through incremental demand charges by the participating entities, require a minimum of two to five years to complete the planning, solicitation of interest, regulatory approval and construction. Recent projects to expand Washington Gas' firm transportation and/or storage capacity completed or in progress, are outlined below:

Projects For Expanding Transportation and Storage Capacity *(In therms)*

Suppliers	Daily Storage Transportation Capacity	Annual Storage Capacity	In-Service Date
Hardy Storage Company LLC[a]	800,000	56 million	Three-year phase-in period beginning in fiscal year 2007
Pine Needle LNG Company LLC[b]	200,000	2 million	May 2006
Duke Energy Gas Transmission Company[b]	700,000	7 million	Fiscal year 2007
Columbia Gas Transmission Corporation[a]	500,000	30 million	Fiscal year 2010

[a] *Supplier delivers the stored natural gas directly to Washington Gas' distribution system.*
[b] *Supplier delivers the stored natural gas indirectly to Washington Gas' distribution system through third-party transportation companies.*

Washington Gas will continue to monitor other opportunities to acquire or participate in obtaining additional pipeline and storage capacity that will improve or maintain the high level of service expected by its customer base.

Sources of Natural Gas

Annual Sendout. As reflected in the table below, there were six sources of delivery through which Washington Gas received natural gas to satisfy the sendout requirements in pipeline year 2006 (November 1, 2005 through October 31, 2006). These same six sources also are expected to be utilized to satisfy sendout requirements in pipeline year 2007 (November 1, 2006 through October 31, 2007). Firm transportation denotes gas transported directly to the entry point of Washington Gas' distribution system in contractually viable volumes. Transportation storage denotes volumes stored by a pipeline during the summer injection season for withdrawal and delivery to the Washington Gas distribution system during the winter heating season to meet load requirements. Peak load requirements are met by: *(i)* underground natural gas storage at the Hampshire storage field in Hampshire County, West Virginia; *(ii)* the local production of propane air plants located at Washington Gas-owned facilities in Rockville, Maryland (Rockville Station) and in Springfield, Virginia (Ravensworth Station) and *(iii)* other peak-shaving sources. Unregulated third-party marketers acquire interstate pipeline and storage capacity and the natural gas commodity on behalf of Washington Gas' delivery service customers, some of which may be provided through transportation, storage and peaking resources provided by Washington Gas to unregulated third-party marketers under tariffs approved by the three public service commissions. These retail marketers have natural gas delivered to the entry point of Washington Gas' delivery system on behalf of those utility customers that have decided to acquire their natural gas commodity on an unbundled basis, as previously discussed.

During pipeline year 2006 (November 1, 2005 through October 31, 2006), total sendout on the system was 1.552 billion therms, as compared to total sendout of 1.676 billion therms during pipeline year 2005. This excludes the sendout of sales and deliveries of natural gas used for electric generation. The decrease in 2006 was the result of weather in pipeline year 2006 that was warmer than pipeline year 2005. The sendout for pipeline year 2007 is estimated at 1.651 billion therms (based on normal weather), excluding the sendout for the sales and deliveries of natural gas used for electric generation. The sources of delivery and related volumes that were used to satisfy the requirements of pipeline year 2006 and those projected for pipeline year 2007 are shown in the following table.

Source of Delivery for Annual Sendout

(In millions of therms)	Pipeline Year	
Source of Delivery	**Actual 2006**	Projected 2007
Firm Transportation	**599**	625
Transportation Storage	**247**	322
Hampshire Storage	**--**	21
Company-Owned Propane-Air Plants	**3**	12
Other Peak-Shaving Sources	**8**	19
Unregulated Third-Party Marketers	**695**	652
Total	**1,552**	1,651

Design Day Sendout. The effectiveness of Washington Gas' gas supply program is largely dependent on the sources used to satisfy delivery requirements for its design day. A design day is the maximum anticipated demand on the natural gas distribution system during a 24-hour period assuming a five-degree Fahrenheit average temperature. For planning purposes, we assume that all interruptible customers will be curtailed on the design day. Washington Gas' current design day demand forecast for the 2006-2007 winter season is 18.0 million therms, and Washington Gas' projected sources of delivery for design day sendout is 19.0 million therms. This provides a reserve margin of approximately 5.56 percent. Washington Gas is currently capable of meeting 72 percent of its design day requirements with storage and peaking capabilities. For its design day, Washington Gas plans for the optimal utilization

of its storage and peaking facilities to reduce its dependency on firm transportation and lower pipeline capacity costs. The following table reflects the sources of delivery that are projected to be used to satisfy the design day sendout estimate for pipeline year 2007.

Projected Sources of Delivery for Design Day Sendout

(In millions of therms)	Pipeline Year 2007	
Source of Delivery	Volumes	Percent
Firm Transportation	5.4	28%
Transportation Storage	5.4	28%
Company-Owned Propane-Air Plants, Hampshire Storage and Other Peaking	7.6	40%
Unregulated Third-Party Marketers	0.6	4%
Total	**19.0**	**100%**

Gulf Coast Natural Gas Supply Issues. During the late summer of 2005, immediately prior to the 2005-2006 winter heating season, the Gulf Coast region experienced a major disruption of natural gas production and processing due to hurricanes Katrina, Rita and Wilma. These natural gas production and processing disruptions resulted in a significant reduction of natural gas available to be delivered from the Gulf Coast region. Historically, Washington Gas received a majority of its natural gas purchases from this region through its contracted interstate pipeline services. According to the latest report from the United States Department of the Interior, Minerals Management Service, over 90 percent of the pre-hurricane natural gas production and processing from the Gulf Coast region became available again to the wholesale market. Given the recovery of available supplies from the Gulf Coast region following the hurricanes, coupled with the availability of natural gas supply from alternative production areas, Washington Gas was able to meet its customers' daily demand for natural gas during the 2005-2006 winter heating season. Storage gas inventory balances were maintained at adequate operational levels throughout the heating season. Through the combination of traditional summer replenishment of its storage resources and the various locations and diversity of natural gas supply sources that are available to it, Washington Gas should have adequate supply to meet its firm service obligations for the 2006-2007 winter heating season.

Should future natural gas production and processing disruptions severely reduce levels of deliverability, then Washington Gas may need to implement contingency plans in order to maximize the number of customers served under such conditions. Contingency plans include requests to conserve to the general population and targeted curtailments to specific sections of the system, consistent with curtailment tariffs approved by regulators in each of Washington Gas' three jurisdictions.

Since hurricanes Katrina, Rita and Wilma, Washington Gas has modified the composition of its natural gas portfolio to include a significantly higher percentage of natural gas supply that is produced from sources outside of the Gulf Coast region, including natural gas supply from the Appalachian and Canadian regions, as well as increased levels of natural gas in the form of vaporized LNG through the Dominion Cove Point (Dominion or Cove Point) LNG terminal. These natural gas supplies are being delivered to Washington Gas' distribution system utilizing existing interstate pipeline resources under contract to Washington Gas that have transportation paths that support natural gas deliveries outside the Gulf Coast region. The diversification of its natural gas portfolio will help Washington Gas to meet customer demand despite unforeseen future supply issues that may arise similar to those resulting from weather events in the Gulf Coast region.

Volatility of Natural Gas Prices

As a result of market concerns about the sufficiency of the supply of natural gas, the hurricanes in the Gulf Coast region and other factors during the 2005-2006 winter heating season, the price of the natural gas commodity paid by Washington Gas' customers rose sharply from levels experienced during the prior year's winter heating season. In fiscal year 2006, higher natural gas prices increased customers' bills dramatically. Under its regulated gas cost recovery mechanisms, Washington Gas records cost of gas expense equal to the cost of gas recovered in revenues from customers. An increase in the cost of gas due to an increase in the purchase price of the natural gas commodity generally has no direct effect on Washington Gas' utility net revenues and net income. However, its net income was reduced in fiscal year 2006 primarily due to higher expenses for uncollectible customer accounts, as well as lower natural gas consumption caused by customer conservation in Virginia and the District of Columbia where these adverse effects on earnings are not addressed through regulatory mechanisms. In Maryland, the RNA and GAC regulatory mechanisms neutralize these effects on Washington Gas' revenues and net income. Increases in the price of natural gas also can affect our operating cash flows, as

well as the competitiveness of natural gas as an energy source (refer to the section below entitled *"Competition—Competition with Other Energy Products"*).

Changes in Natural Gas Consumption

Natural gas supply requirements may be affected by changes in natural gas consumption by customers. Natural gas usage per customer may decline as customers change their consumption patterns in response to: *(i)* more volatile and higher natural gas prices, as discussed above and *(ii)* customers' replacement of older, less efficient gas appliances with more efficient appliances. In each jurisdiction where it operates, Washington Gas' recent rate case proceedings reflect these changes in customer usage profiles. In both the District of Columbia and Virginia jurisdictions, changes in customer usage by existing customers that occur subsequent to these recent rate case proceedings will have the effect of reducing revenues, which is offset by the favorable effect of adding new customers. Effective October 1, 2005, pursuant to an RNA mechanism approved by the PSC of MD, changes in customer usage by existing customers that occur subsequent to recent rate case proceedings in the Maryland jurisdiction generally will not reduce revenues, but rather will have the effect of stabilizing the level of delivery charge revenues received from customers on a monthly basis (refer to the section entitled *"Jurisdictional Rates and Regulatory Matters—Maryland Jurisdiction"* for a further discussion of this billing adjustment mechanism).

COMPETITION

Competition with Other Energy Products

Washington Gas faces competition based on customers' preference for natural gas compared to other energy products and the comparative prices of those products. The most significant product competition occurs between natural gas and electricity in the residential market. The residential market generates a significant portion of Washington Gas' net income. In its service territory, Washington Gas continues to attract the majority of the new residential construction market. Consumers' continuing preference for natural gas allows Washington Gas to maintain a strong market presence.

Washington Gas has generally maintained a price advantage over competitive electricity supply in its service area for traditional residential uses of energy such as heating, water heating and cooking. Price volatility in the wholesale natural gas commodity market during the 2005-2006 winter heating season resulted in significant increases in the cost of natural gas billed to customers (refer to the section entitled *"Volatility of Natural Gas Prices"*). Such increases have resulted in a reduction in the traditional price advantage of natural gas over electricity.

The price advantages of electricity have been partially caused by artificial price caps on electricity sold by electric utilities. These price caps have expired in Maryland and the District of Columbia, and utility sales service price caps in Virginia will expire in 2010. Since the expiration of price caps in Maryland and the District of Columbia, market-based utility standard offer service rates have been put into effect in these jurisdictions which are subject to change in June of each year due to changes in the wholesale electricity market. The cost of generating electricity is affected by the cost of fuel used to generate electricity. As the prices of those fuels rise and existing supply contracts for those fuels between electric generators and fuel suppliers expire, the price of electricity will likely rise in relation to the current price for other forms of energy.

In June 2006, a change in standard offer service prices in Maryland and the District of Columbia resulted in significantly increased electricity prices in these jurisdictions. Although price volatility in the wholesale natural gas commodity market reduced the price advantage of natural gas over electricity, the significant rise in electric prices has restored some of the price advantage of natural gas.

Furthermore, as discussed below, the continued restructuring in both the natural gas and electric industries is leading to changes in traditional utility pricing models. As part of the electric industry restructuring effort, large and medium commercial markets are moving towards competitive retail supply contracts with third-party marketers of electricity, such as WGEServices. Competitive electric supply markets may result in lower comparative pricing for electric service and other alternative energy sources, including natural gas. These changes could result in increased competition for Washington Gas.

In the interruptible market, fuel oil is the prevalent energy alternative to natural gas. Washington Gas' success in this market depends largely on the relationship between natural gas and oil prices. The supply of natural gas primarily is derived from domestic sources, and the relationship between supply and demand generally has the greatest impact on natural gas prices. As a large portion of oil comes from foreign sources, political events can have significant influences on oil supplies and, accordingly, oil prices. The

introduction of non-domestic supplies of LNG into the United States natural gas market may affect supply levels and have an impact on natural gas prices. To date, the effect of LNG on supply levels has been minimal.

Deregulation

In each of the jurisdictions (the District of Columbia, Maryland and Virginia) served by Washington Gas, regulators and utilities have implemented customer choice programs. These programs allow customers to choose to purchase their natural gas and/or electric commodity from unregulated third-party marketers, rather than purchasing these commodities as part of a bundled service from the local utility. When customers choose to purchase their natural gas commodity from unregulated third-party marketers on an unbundled basis, Washington Gas' utility net revenues or net income are not affected since Washington Gas charges its customers the cost of gas without any mark-up. However, these customer choice programs provide unregulated third-party marketers, such as WGEServices, with opportunities to profit from the sale of the natural gas commodity or electricity in competitive retail markets. It also enables customers to have competitive choices for natural gas and electricity. Participating in this evolving marketplace also poses risks and challenges that must be addressed in our current and future strategies.

The Natural Gas Delivery Function

The natural gas delivery function, the core business of Washington Gas, continues to be regulated by local regulatory commissions. In developing this core business, Washington Gas has invested nearly $2.9 billion as of September 30, 2006 to construct and operate a safe and reliable natural gas distribution system. Because of the high fixed costs and significant safety and environmental considerations associated with building and operating a distribution system, Washington Gas expects to continue being the only owner and operator of a natural gas distribution system in its current franchise area for the foreseeable future. The nature of Washington Gas' customer base and the distance of most customers from interstate pipelines mitigate the threat of bypass of its facilities by other potential delivery service providers.

Washington Gas expects that local regulatory commissions will continue to set the prices and terms for delivery service that give it an opportunity to earn a just and reasonable rate of return on the capital invested in its distribution system and to recover reasonable operating expenses. Washington Gas plans to continue constructing, operating and maintaining its natural gas distribution system, and will incur costs necessary to ensure the safety and reliability of its system, and that operating issues are addressed in a timely and adequate manner.

The Merchant Function and Natural Gas Unbundling

At September 30, 2006, customer choice programs for natural gas customers were available to all of Washington Gas' regulated utility customers in the District of Columbia, Maryland and Virginia. Of the 1.032 million active customers at September 30, 2006, approximately 147,000 customers purchased their natural gas commodity from unregulated third-party marketers. The following table provides the status of customer choice programs in Washington Gas' major jurisdictions at September 30, 2006.

Status of Customer Choice Programs
At September 30, 2006

Jurisdiction	Customer Class	Eligible Customers	
		Total	% Participating
District of Columbia	Firm:		
	Residential	137,277	9%
	Commercial	13,130	34%
	Interruptible	229	86%
Maryland	Firm:		
	Residential	391,731	15%
	Commercial	29,223	42%
	Interruptible	262	100%
Virginia	Firm:		
	Residential	433,215	12%
	Commercial	26,632	29%
	Interruptible	217	93%
Total		**1,031,916**	**14%**

Washington Gas prudently enters into contracts to purchase the natural gas commodity and, therefore, concludes that the costs being incurred should be recoverable from customers. Currently, Washington Gas' jurisdictional tariffs contain gas cost mechanisms that allow it to recover the invoice cost of gas, including both the commodity cost of gas and the interstate pipeline capacity services, applicable to firm customers. If future unbundling or other initiatives remove the current gas cost recovery provisions, Washington Gas could be adversely impacted to the extent it cannot fully recover the cost of the natural gas commodity if purchased at above-market prices. Washington Gas currently has recovery mechanisms for such potentially stranded costs in the District of Columbia, Maryland and Virginia.

The same jurisdictional tariffs that allow Washington Gas to recover the invoice cost of gas applicable to firm customers also allow the utility to recover from third-party marketers, 100 percent of the cost of the storage and peak shaving capacity that Washington Gas dedicates to serving unbundled service customers who purchase their natural gas from a third-party marketer. Additionally, Washington Gas currently has mechanisms approved by each of its local commissions to recover some portion of the costs of transportation capacity from unregulated third-party marketers. Washington Gas is generally renewing long-term capacity contracts to meet its forecasts of continued growth in customer's firm gas requirements and to comply with regulatory mechanisms to provide for or make available such resources to retail marketers serving customers in the customer choice programs.

To maximize the value of its long-term capacity, Washington Gas has entered into contracts with unregulated wholesale energy services companies that make use of the utility's firm storage and transportation rights when Washington Gas does not need these rights, and to make off-system sales when such storage and transportation rights are under-utilized. Washington Gas continues to pay the fixed charges associated with the firm storage and transportation contracts used to make these sales. The sale of these rights are accounted for as revenues under regulated margin-sharing arrangements that vary by jurisdiction whereby a significant portion of these revenues is shared with Washington Gas' customers as a reduction in natural gas costs, otherwise recoverable from firm customers. Washington Gas also has undertaken a portion of this responsibility in order to maximize the potential value of such resources and subsequently lower the cost of gas to its sales service customers. These transactions include fixed-priced and market-priced purchases and sales which Washington Gas has matched with the purchase of derivative instruments that simultaneously fix the economic profit on these transactions.

UNREGULATED RETAIL ENERGY-MARKETING OF NATURAL GAS AND ELECTRICITY

As the role of regulated utilities in the merchant function may decrease over time, opportunities emerge for unregulated natural gas and electric providers. In the deregulated marketplace, third-party marketers have profit-making opportunities from the sale of the commodity, but they also assume the risk of loss.

In fiscal year 1997, we established WGEServices as an unregulated retail energy-marketing subsidiary. WGEServices sells natural gas and electricity to residential, commercial and industrial customers inside and outside of the Washington Gas service area. At September 30, 2006, 2005 and 2004, WGEServices had natural gas customers totaling approximately 142,700, 144,800 and 150,800, respectively. WGEServices had electric customers totaling approximately 63,300, 36,200 and 44,500 at September 30, 2006, 2005 and 2004, respectively. WGEServices' operating revenues for fiscal years 2006, 2005 and 2004 were $1.0 billion, $773.0 million and $789.9 million, respectively. WGEServices' net income was $13.3 million, $22.3 million and $8.3 million for fiscal years 2006, 2005 and 2004, respectively.

Natural Gas Supply

WGEServices competes with other third-party marketers to sell the unregulated natural gas commodity to customers. Marketers of the natural gas commodity compete largely on price, and gross margins are relatively small. Consequently, gross margins for the sale of unregulated natural gas are typically lower than those earned by Washington Gas.

WGEServices faces risks associated with its gas supply because it may experience a difference between contracted gas purchase quantities and contractual gas sales commitments. To minimize this risk, WGEServices manages its natural gas contract portfolio by closely matching the timing of gas purchases from suppliers with sales commitments to customers. WGEServices also purchases its gas from a number of wholesale suppliers in order to avoid relying on any single provider for its natural gas supply. Additionally, WGEServices maintains gas storage inventory that is assigned to it by natural gas utilities such as Washington Gas. This storage inventory enables WGEServices to meet daily and monthly fluctuations in demand caused by variations in weather from normal. WGEServices may, from time to time, enter into derivative contracts, including weather derivatives, in order to balance its sales commitments with the amount of gas it must purchase to satisfy those commitments, or for purposes of fixing the price at which WGEServices may have to purchase or sell gas. WGEServices has a risk management policy in place and periodically reassesses its policy to determine its adequacy to mitigate risks in changing markets. For a further discussion about WGEServices' exposure to and management of market risks, refer to the section entitled *"Market Risk"* included in Management's Discussion.

WGEServices purchases a portion of its natural gas supply from the Gulf Coast region. Purchase commitments from certain of WGEServices' Gulf Coast-based natural gas suppliers were interrupted by the supply shortage in the Gulf Coast region in the immediate aftermath of the hurricanes during the fall 2005 season. During the 2005-2006 winter heating season, all of WGEServices' contracted natural gas supplies from the Gulf Coast region flowed as contracted, and WGEServices met its customers' daily demand for natural gas and achieved its required storage inventory balances.

In meeting its natural gas supply needs for the 2006-2007 winter heating season and beyond, WGEServices expects to continue to rely on a diverse set of supply sources, including city-gate delivered supplies, natural gas in storage and LNG from the Cove Point terminal.

Electricity Supply

Customer choice programs for electric customers have been implemented in each jurisdiction in which Washington Gas operates. Similar to the natural gas industry, participants in these programs can choose either to continue purchasing bundled electricity service from their local electric distribution utility or to purchase electricity from a third-party marketer. WGEServices competes with other third-party marketers to sell electric supply services to customers. Marketers of electric supply service compete largely on price, and gross margins are relatively small.

As of September 30, 2006, WGEServices' electric customers grew 75 percent when compared to the number of customers as of September 30, 2005. This customer growth was principally the result of new competitive opportunities that emerged near the end of the third quarter of fiscal year 2006 due to sharp increases in competing rates offered by electric utilities in Maryland and Delaware. In other locations, however, future opportunities to add new electric customers may continue to be limited by the relationship between electric Standard Offer Service (SOS) rates offered by local electric utilities and market prices for electricity. Certain SOS rates in WGEServices' market area continue to be below current market prices. In certain cases, electric utilities have entered into

wholesale contracts to supply their SOS customers, prior to an increase in fuel prices required to generate electricity. In other cases, electric utilities continue to provide service under previously established rates that are capped.

WGEServices procures electricity supply under contract structures in which WGEServices assumes the responsibility of matching its customer requirements with its supply purchases. WGEServices assembles the various components of supply, including electric energy, capacity, ancillary services and transmission service from multiple suppliers to match its customer requirements in accordance with its risk management policy. To the extent WGEServices has not matched its customer requirements with its supply purchases, it could be exposed to electricity commodity price risk. WGEServices' electric business also is exposed to fluctuations in weather. Generally, WGEServices makes purchases under fixed-volume contracts that are based on certain weather assumptions. If there are significant deviations in weather from these assumptions, WGEServices may incur price and volume variances that could negatively impact its expected gross margins.

For a small percentage of its electricity supply, WGEServices purchased full requirements services from wholesale electricity suppliers under master purchase and sale agreements, including electric energy, capacity and certain ancillary services, for resale to retail electric customers. On October 19, 2006, WGEServices terminated all remaining full requirements contracts and received a small termination settlement.

POTENTIAL FOR FURTHER UNBUNDLING

Currently, Washington Gas provides customer services, such as preparing bills, reading meters and responding to customer inquiries, as part of its core utility function. Unregulated third-party marketers have the option to assume responsibility for bill preparation and customer collections. In addition to billing and collecting from customers for the natural gas commodity, third-party marketers' bills may include natural gas delivery charges due Washington Gas, which they subsequently remit to it. Although Washington Gas still provides most customer services on a bundled basis, the potential exists for future deregulation initiatives to separate these services from the core utility function. In that case, customers could choose to have unregulated competitors provide these services.

To remain competitive, we continuously strive to improve quality and efficiency and to reduce costs to achieve market-level performance. Accordingly, we will continue to look for opportunities to profit from further unbundling.

OPERATING ISSUES IN PRINCE GEORGE'S COUNTY, MARYLAND

Description of Operating Issues and Related Causes

On April 1, 2005, Washington Gas announced that it would address a significant increase in the number of natural gas leaks on its distribution system in a portion of Prince George's County, Maryland. Washington Gas retained a consultant, ENVIRON International Corporation (Environ), to determine the reason for the increase in leaks in the affected area of Prince George's County. Based on the work conducted to date by Environ, there is a combination of three contributing factors to the higher leak rates of seals on couplings. However, the contributing factor that is unique to the affected area is the change in the gas composition resulting from a change in the gas supply arising from the reactivation of the Cove Point LNG terminal owned by Dominion Resources, Inc. The Cove Point gas has a lower concentration of HHCs than domestic natural gas. The consultant's report indicated that a characteristic of the rubber material comprising the seals in the couplings is the ability of the seals to both adsorb and desorb HHCs. When seals are exposed to higher levels of HHCs, they swell in size and cause a tighter seal. However, when gas, such as the gas from the Cove Point terminal is introduced and it has a lower level of HHCs, the seals shrink in size and there is a greater propensity for those seals to cause the couplings to leak.

Environ also considered the age of the couplings and the colder ground temperature during the winter as potential contributing factors to the higher leak rate. However, both the age of the couplings and the colder ground temperatures are common to couplings in other areas of Washington Gas' service territory where leak patterns have not been observed like those in the affected area of Prince George's County. Thus, in our opinion, the relevant change that explains the higher incidence of leaks in the affected area of Prince George's County is the composition of the gas resulting from the introduction of gas from the Cove Point LNG terminal.

Washington Gas has continued to evaluate the causes and possible solutions related to the higher leak rate in the seals discussed above. Data and analyses continue to confirm that changes in gas composition explain the higher leak rates. A report by another consultant, Polymer Solutions, Inc., dated September 27, 2005, discussed and confirmed that changing gas composition has an effect on coupling seal materials. A later report from Environ, dated April 10, 2006, concluded in its testing of full component mechanical

couplings removed from Washington Gas' distribution system within the affected area of Prince George's County that the seals on the couplings will shrink and swell with the exposure to the change in levels of HHCs between domestic natural gas and re-vaporized LNG. Testing is continuing on coupling seal materials to attempt to determine optimum HHC injection rates necessary to maintain the integrity of the seals and return leak rates for the couplings to normal maintenance levels experienced before the introduction of gas coming from the Cove Point terminal.

Given the increase in the number of natural gas leaks experienced in the affected area of Prince George's County, Maryland in fiscal year 2005, Washington Gas announced in that year that it would replace gas service lines and rehabilitate gas mains that contain the applicable mechanical couplings in the affected area of the distribution system in Prince George's County (the rehabilitation project), with a projected date of completion by the end of December 2007. The original estimate of the cost of the rehabilitation project is $144 million. This cost estimate could differ materially from the actual costs incurred for the work associated with this project. Washington Gas' planned capital expenditures for fiscal years 2006 through 2008 reflect this cost estimate. As of September 30, 2006, Washington Gas had completed approximately 50 percent of the work related to the rehabilitation project.

We consider the cost of the rehabilitation project described above necessary to provide safe and reliable utility service. We anticipate that costs such as these eventually will be recognized in the ratemaking process as reasonable. Washington Gas has not yet requested recovery of the capital expenditures and maintenance costs being incurred. However, we are also considering the effect of these capital expenditures on Washington Gas' ability to earn its allowed rate of return in Maryland, and we are evaluating the most appropriate options to enable full and timely recovery of, and return on, the amounts being expended. There can be no assurance at this time that recovery in rates will be allowed or at what point in time such recovery may begin to be reflected in rates.

We anticipate that additional volumes of gas from the Cove Point terminal may flow through facilities in both the affected area of Prince George's County and in other areas of Washington Gas' distribution system as a result of the FERC's June 16, 2006 order approving Dominion's application to expand the capacity and output of the Cove Point terminal (see the section below entitled *"Proposed Cove Point Expansion"*). As such, Washington Gas has examined potential approaches that will enable it to protect against the adverse effects of the Cove Point gas. The original $144 million cost estimate of the rehabilitation project previously discussed does not consider any costs that have been incurred to date or that will potentially be incurred associated with implementing any of these actions. Based upon the scientific evidence available to date, Washington Gas constructed the facilities necessary to inject HHCs into the gas stream at the gate station that exclusively receives gas from the Cove Point terminal and serves the affected area of Prince George's County, Maryland where the increase in gas leaks had been observed. This facility became operational in January 2006 at a cost of approximately $3.2 million.

Laboratory tests have shown that the injection of HHCs into the type of gas coming from the Cove Point terminal can be effective in re-swelling the seals in couplings which increases their sealing force and, thus, reduces the propensity for the couplings to leak. Furthermore, since the injection facility became operational in January 2006, Washington Gas has been evaluating the effectiveness of this HHC injection process on the couplings under field conditions. As of September 30, 2006, testing had concluded that the HHCs being injected at this gate station remain in the gas stream and are carried throughout that portion of the distribution system where Washington Gas intends for them to flow.

Washington Gas has observed a notable reduction in leak rates since the HHC injection facility became operational in January 2006. Given this observation, coupled with the results of the laboratory tests performed to date that support the effectiveness of the HHC injection process, we plan to modify the scope of work on the rehabilitation project through the 2006-2007 winter heating season, and anticipate that the overall scope and original $144 million cost estimate of this project may be modified if the expected results materialize in the coming winter. Washington Gas will continue collecting and analyzing leak data in the affected area of Prince George's County through the 2006-2007 winter heating season and we will continue performing special leak surveys before drawing a definitive conclusion regarding the level of effectiveness of the injection process and the overall scope and cost estimate of the rehabilitation project that ultimately will be incurred. Until such time, Washington Gas will continue its rehabilitation efforts within the affected area in Prince George's County at modified levels, and will concurrently continue its gas conditioning solution.

Proposed Cove Point Expansion

In fiscal year 2005, Dominion (the applicant) requested authorization from the FERC to expand the capacity and output of its Cove Point LNG terminal. This expansion would result in a substantial increase of Cove Point gas introduced into the Washington Gas distribution system in areas that have distribution and service lines constructed of similar materials and in a similar manner to those in the affected area of Prince George's County. This could increase the exposure of other areas within the Washington Gas distribution system to Cove Point gas that may be either minimally blended with domestic natural gas pipeline supply or completely

unblended with any other gas, thereby potentially causing an increase in leaks on couplings in additional parts of the Washington Gas distribution system. To address this potential risk, Washington Gas has begun the planning necessary to construct two additional facilities to inject HHCs at gate stations in anticipation that more gas from the Cove Point terminal may begin flowing into the interconnected pipelines in fiscal year 2008 or thereafter and, therefore, into other areas of Washington Gas' distribution system. Washington Gas anticipates that the next gate station injection facility will be operational by the 2007-2008 winter heating season.

The estimated cost of each of the additional HHC injection facilities will range from an estimated $3 million to $4 million. Washington Gas expects that the cost of these facilities should be includible in the rate base upon which Washington Gas is allowed to earn an allowed rate of return. The estimated cost of these facilities does not include the cost of the purchase of HHCs. At September 30, 2006, Washington Gas had incurred $2.0 million of HHC purchasing costs, and had deferred $575,000 of these costs on the balance sheet as a regulatory asset to be recovered from customers in the future. Currently, Washington Gas is collecting the cost of HHCs in its PGC provision in the District of Columbia from its sales customers. Washington Gas currently is not collecting the cost allocable to Virginia or Maryland customers associated with the purchase of HHCs. The regulatory bodies having jurisdiction over Washington Gas' rates will determine the ultimate amount that is recoverable from customers for the cost of these HHCs (refer to the section entitled *"Rates and Regulatory Matters"*).

Washington Gas has not yet gathered enough evidence to reach a definitive conclusion that the injection of HHCs into the gas distribution system will be completely effective in preventing additional leaks or retarding the rate at which additional leaks may occur in the gas distribution system if additional volumes from the Cove Point terminal are introduced. The winter of 2005-2006 was too mild for a meaningful comparison with the period during which the unusual leak pattern presented itself in the affected area of Prince George's County. Washington Gas continues to gather and evaluate field and laboratory evidence about this gas conditioning solution. The timing and implementation of decisions by the FERC governing the proposed expansion and the planning and implementation by Dominion may affect our ability to implement our plans before our system experiences increased flows of gas from Cove Point. Construction of these additional facilities may not be timely, permitted or feasible. If the facilities are constructed, the injection of additional HHCs may not be effective or only partially effective in preventing additional leaks on couplings in the gas distribution system. If the injection of HHCs into the gas distribution system is not effective or only partially effective in preventing additional leaks on couplings, Washington Gas will seek an acceptable and viable alternative to address this issue. If the planned actions of treating the Cove Point gas are not successful or only partially effective in preventing additional leaks on couplings, and if we are not able to determine a satisfactory alternative solution on a timely basis, additional operating expenses and capital expenditures may be necessary to contend with the receipt of increased volumes of gas from the Cove Point LNG terminal into Washington Gas' distribution system.

Notwithstanding Washington Gas' current and potential future actions before its local regulatory commissions with respect to the recovery of costs related to the construction of the injection facilities and the purchase of HHCs, our position is that any costs associated with the remediation related to the gas from the Cove Point LNG terminal should be the responsibility of the parties that are introducing gas from the Cove Point terminal into the interstate pipeline transmission system that is then introduced into the distribution system of Washington Gas. Therefore, as further discussed below, Washington Gas is pursuing certain remedies, and will pursue all remedies, it has before the FERC and other entities to assure that its customers are only paying their appropriate share of the costs of the remediation to maintain the safety of the Washington Gas distribution system. To the extent that Washington Gas receives approval and recovers costs from its retail customers for actions it has taken to maintain the safety and integrity of its distribution system, Washington Gas will apply any compensation received as a result of current or future actions before the FERC or against others, as an offset to future costs collected from retail customers.

Request for FERC Action

In November 2005, Washington Gas requested the FERC to invoke its authority to require Dominion to demonstrate that the increased volumes of the Cove Point gas would flow safely and reliably through the Washington Gas distribution system. Washington Gas specifically requested that the proposed expansion of the Cove Point LNG terminal be denied until the applicant has shown that the Cove Point gas: *(i)* is of such quality that it is fully interchangeable with the natural gas historically received by Washington Gas and *(ii)* will not cause harm to its customers or to the infrastructure of Washington Gas' distribution system.

The FERC convened a procedural conference in February 2006 to receive information related to the issues raised by Washington Gas concerning the compatibility of gas from the Cove Point terminal and the safety of its distribution system should significantly larger volumes of gas from the Cove Point terminal flow into the interconnected interstate pipelines that serve Washington Gas. Washington Gas presented operational data and scientific evidence supporting Washington Gas' assertions that the

unblended re-vaporized LNG is the unique cause of the increase in leaks. Washington Gas also provided the FERC with all data that Washington Gas had made available for Environ's review.

On June 16, 2006, the FERC issued an order authorizing the applicant's request to expand the capacity and output of its Cove Point LNG terminal and, thereby, denying Washington Gas' request to require the applicant to demonstrate the safety and reliability of the Cove Point gas flowing through the Washington Gas distribution system. Furthermore, the FERC stated that, although it could not rule out the unblended re-vaporized LNG as a cause of the leaks on the Washington Gas distribution system, Washington Gas' use of hot tar as a corrosion protectant, coupled with an increase in the operating pressure of its system "were the principal causative factors" in the increased leaks.

On July 17, 2006, Washington Gas filed a Request for Rehearing with the FERC to seek modification of the FERC's June 16, 2006 order that authorized the Cove Point expansion. In its request, Washington Gas asserted, among other things, that its application of hot tar was an acceptable industry practice for corrosion protection when mechanical couplings were installed between the 1950s and 1970s, and that this practice was used throughout its service territory. The increase in leaks occurred only in the area that consistently receives Cove Point gas as its sole source of supply. Washington Gas further asserted that its operating pressure has remained constant in the affected area since the mid-1980s.

Washington Gas is pursuing the rehearing because specific scientific evidence, points of law and potentially serious safety issues were not adequately addressed by the FERC in its June 16, 2006 order on the Cove Point expansion. Washington Gas is one of several entities requesting such a rehearing. Filings by the PSC of MD and other organizations, such as KeySpan Corporation, state that the FERC order failed, in some way, to protect a wide range of consumers' interests.

Washington Gas is committed to the use of natural gas from the Cove Point terminal to satisfy the needs of its customers. Washington Gas is willing to work with Dominion Cove Point LNG, the shippers who bring LNG into the Cove Point terminal and the interstate pipelines that deliver gas to Washington Gas in order to achieve and implement an appropriate solution to the issue of gas interchangeability affecting its system. Washington Gas will continue taking steps to protect its system by conditioning gas from Cove Point, and by proceeding with its ongoing rehabilitation project in the affected portion of Prince George's County. The extent to which this project is fully completed will depend on the effectiveness of the injection process in the affected area of Prince George's County during the winter of 2006-2007.

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations related to environmental matters. These evolving laws and regulations may require expenditures over a long timeframe to control environmental effects. Almost all of the environmental liabilities we have recorded are for costs expected to be incurred to remediate sites where we or a predecessor affiliate operated manufactured gas plants (MGP). Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited, to the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete or experience with existing technology that proves ineffective;
- the level of remediation required and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

Washington Gas has identified up to ten sites where it or its predecessors may have operated MGPs. Washington Gas last used any such plant in 1984. In connection with these operations, we are aware that coal tar and certain other by-products of the gas manufacturing process are present at or near some former sites, and may be present at others. Based on the information available to us, we have concluded that none of the sites are likely to present an unacceptable risk to human health or the environment.

At one of the former MGP sites, studies show the presence of coal tar under the site and an adjoining property. Washington Gas has taken steps to control the movement of contaminants into an adjacent river by installing a water treatment system that removes and treats contaminated groundwater at the site. Washington Gas received approval from governmental authorities for a

comprehensive remediation plan for the majority of the site that will allow commercial development of Washington Gas' property. Washington Gas has entered into an agreement with a national developer for the development of this site in phases. The first two phases have been completed, with Washington Gas retaining a ground lease on each phase. The owner of the affected adjoining property has issued a Record of Decision for that portion of the site, and Washington Gas will negotiate an agreement with the owner to perform the remediation. On September 21, 2006, governmental authorities notified Washington Gas of their desire to have the utility investigate and remediate river sediments in the area directly in front of the former MGP site. There has been no agreement among Washington Gas and governmental authorities as to the type and level of sediment investigation and remediation that should be undertaken for this area of the river; accordingly, we cannot estimate at this time the potential future costs of such investigation and remediation.

At a second former MGP site and on an adjacent parcel of land, Washington Gas developed a "monitoring-only" remediation plan for the site. This remediation plan received approval under a state voluntary closure program.

We do not expect that the ultimate impact of these matters will have a material adverse effect on our capital expenditures, earnings or competitive position. At the remaining eight sites, either the appropriate remediation is being undertaken, or no remediation should be necessary. See Note 14 of the Notes to Consolidated Financial Statements for a further discussion of environmental response costs.

OTHER INFORMATION ABOUT THE BUSINESS

Washington Gas is not dependent upon a single customer or group of customers such that the loss of any one or more of such customers would have a significant adverse effect on its business. As previously discussed, Washington Gas served over one million customers at September 30, 2006. Our energy-marketing segment is not heavily dependent on any one customer or group of customers. The commercial HVAC segment derived approximately 67 percent and 54 percent of revenues from various agencies of the Federal Government, in fiscal years 2006 and 2005, respectively.

Washington Gas is weather-sensitive and seasonal since the majority of its business is derived from residential and small commercial customers who use natural gas for space heating purposes. In fiscal year 2006, 76 percent of the total therms delivered in Washington Gas' franchise area, excluding deliveries for electric generation, occurred in its first and second fiscal quarters. Washington Gas' earnings are typically generated during these two quarters, and the regulated utility historically incurs net losses in the third and fourth fiscal quarters. The timing and level of approved rate increases can affect the results of operations. The seasonal nature of Washington Gas' business creates large variations in short-term cash requirements, primarily due to the fluctuations in the level of customer accounts receivable, unbilled revenues and storage gas inventories. Washington Gas finances these seasonal requirements primarily through the sale of commercial paper and unsecured short-term bank loans.

The operations of WGEServices are also seasonal, with large amounts of electricity being sold in the summer months and large amounts of natural gas being sold in the winter months. Working capital requirements vary significantly during the year, and these variations are financed primarily through WGL Holdings' issuance of commercial paper and unsecured short-term bank loans.

Our research and development costs during fiscal years 2006, 2005 and 2004 were not material.

At September 30, 2006, we had 1,818 employees comprising 1,606 utility and 212 non-utility employees.

Our Code of Conduct, Corporate Governance Guidelines, and charters for the Governance, Audit and Human Resources committees of the Board of Directors are available on the corporate Web site www.wglholdings.com. Copies also may be obtained by request to the Corporate Secretary at WGL Holdings, Inc., 101 Constitution Ave., N.W., Washington, D.C. 20080. We make available free of charge on our corporate Web site, our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, and any amendments, as soon as reasonably practicable after such reports have been electronically filed with or furnished to the Securities and Exchange Commission (SEC). Additional information about WGL Holdings is also available on its Web site. Our Chairman and Chief Executive Officer certified to the New York Stock Exchange (NYSE) on March 15, 2006 that, as of that date, he was unaware of any violation by WGL Holdings of the NYSE's corporate governance listing standards.

ITEM 1A. RISK FACTORS

The risk factors described below should be read in conjunction with other information included or incorporated by reference in this Annual Report on Form 10-K, including an in-depth discussion of these risks in the section entitled "*Management's Discussion and Analysis of Financial Condition and Results of Operations.*" The risks and uncertainties described below are not the only risks and uncertainties facing us. Additional risks and uncertainties not presently known or that we currently have concluded are immaterial may also adversely affect us.

HOLDING COMPANY

Our business may be adversely affected if we are unable to pay dividends on our common stock and principal and interest on our outstanding debt.

We, WGL Holdings, are a holding company whose assets consist primarily of investments in our subsidiaries. Accordingly, we conduct all of our operations through our subsidiaries. Our ability to pay dividends on our common stock and to pay principal and accrued interest on our outstanding debt depends on the payment of dividends to us by Washington Gas or the repayment of funds to us by our principal subsidiaries. Payments to us by our subsidiaries depend, in turn, upon their results of operations and cash flows, which are subject to the risk factors, discussed below. The extent to which our subsidiaries do not pay dividends or repay funds to us may adversely affect our ability to pay dividends to holders of our common stock and principal and interest to holders of our debt.

If we are unable to access capital or to access capital cost effectively, our subsidiaries' business may be adversely affected. Additionally, a downgrade in our credit ratings could adversely affect our access to capital markets.

Our ability to obtain adequate and cost effective capital depends largely on our credit ratings, which are greatly affected by our subsidiaries' financial performance and the liquidity of financial markets. A downgrade in our current credit ratings could adversely affect our access to capital markets, as well as our cost of capital.

WASHINGTON GAS LIGHT COMPANY

Washington Gas' operations, earnings and cash requirements are highly weather sensitive and seasonal.

The operations of Washington Gas, our regulated utility subsidiary, are weather sensitive and seasonal, with a significant portion of revenues derived from the delivery of natural gas to residential and commercial customers who use natural gas for space heating. Weather conditions directly influence the volume of natural gas delivered to customers. The rates Washington Gas charges its customers are determined on the basis of expected normal weather conditions. Generally, Washington Gas delivers more than 75 percent of its total natural gas volumes, excluding deliveries for electric generation, in our first and second fiscal quarters. Deviations in weather from normal levels and the seasonal nature of Washington Gas' business can create large variations in earnings and short-term cash requirements.

Changes in the regulatory environment or unfavorable rate regulation, that can be affected by new laws or political considerations, may restrict or delay Washington Gas' ability to earn a reasonable rate of return on its invested capital to provide utility service and to fully recover its operating costs.

Washington Gas is regulated by the PSC of DC, the PSC of MD and the SCC of VA. These regulatory commissions generally have authority over many of the activities of Washington Gas' business including, but not limited to, the rates it charges to its customers, the amount and type of securities it can issue, the nature of investments it can make, the nature and quality of services it provides, safety standards and other matters.

Because the rate setting process is based, in part, on historical financial information and estimates that are inherent in the accounting process, the rates Washington Gas charges its customers may not allow Washington Gas' business to earn a reasonable rate of return on actual invested capital and fully recover actual operating costs. Regulatory commissions have the authority to grant rate increases, order rate decreases or require no change in the rates Washington Gas charges its customers. These regulators also may modify Washington Gas' rates to change the level, type and methods that it utilizes to recover its costs, including the costs to acquire, store, transport and deliver natural gas. Some of these supply costs are incurred under long-term contracts. The extent to which the actions of regulatory commissions restrict or delay Washington Gas' ability to earn a reasonable rate of return on invested capital and/or fully recover operating costs may adversely affect its results of operations, financial condition and cash flows.

Washington Gas' ability to meet customers' natural gas requirements may be impaired if its contracted gas supplies and interstate pipeline and storage services are not available or delivered in a timely manner.

Washington Gas is responsible for acquiring sufficient natural gas supplies and interstate pipeline and storage capacity to meet current and future customers' annual and seasonal natural gas requirements. If Washington Gas is not able to maintain a reliable and adequate natural gas supply and sufficient pipeline capacity to deliver that supply, it may be unable to meet its customers' requirements. If Washington Gas is unable to meet customers' demand requirements, this could adversely affect its results of operations, financial condition and cash flows.

Washington Gas needs to acquire additional capacity to deliver natural gas on the coldest days of the year, and it may not receive the necessary authorizations to do so in a timely manner.

Washington Gas plans to construct a one billion cubic foot liquefied natural gas (LNG) storage facility in Chillum, Maryland, to meet its customers' forecasted demand for natural gas. The new storage facility is currently expected to be completed and in service by the 2011-2012 winter heating season. If we are not permitted or are not able to construct this planned facility on a timely basis for any reason, the availability of the next best alternative (which is to acquire additional interstate pipeline transportation or storage capacity) may be limited by market supply and demand, and the timing of Washington Gas' participation in new interstate pipeline construction projects. This could cause an interruption in Washington Gas' ability to satisfy the needs of some of its customers, which could adversely affect its results of operations and cash flows.

Decreases in natural gas consumption by Washington Gas' customers may negatively affect revenues and net income.

Increases in the cost of gas due to increases in the purchase price of the natural gas commodity generally have no direct effect on Washington Gas' revenues and net income because regulatory mechanisms allow these increased costs to be reflected in the rates charged to customers. However, a rise in natural gas prices may reduce Washington Gas' net income due to: *(i)* lower firm sales margins from decreased natural gas deliveries that may result from customer conservation; *(ii)* increased short-term interest expense to finance higher accounts receivable balance and *(iii)* higher expenses that may be incurred for uncollectible customer accounts.

In addition to these short-term impacts of higher natural gas prices, a sustained period of higher prices may result in longer term decreases in natural gas use per customer as customers change their consumption patterns by replacing older, less efficient gas appliances with more efficient appliances. The resulting conservation would reduce Washington Gas' net revenues and net income in those jurisdictions where Washington Gas has not filed for or received approval from its regulators to implement mechanisms that mitigate the financial effect of such efficiency improvements.

Operating issues could affect public safety and the reliability of Washington Gas' natural gas distribution system which could have adverse financial implications.

Washington Gas' business is exposed to operational issues that could affect the public safety and reliability of its natural gas distribution system. Operational issues such as leaks, mechanical problems and accidents could result in significant costs to Washington Gas' business and loss of customer confidence. The occurrence of any such operational issues could adversely affect Washington Gas' results of operations, financial condition and cash flows. If Washington Gas is unable to recover from customers through the regulatory process all or some of these costs and its authorized rate of return on these costs, this also could adversely affect Washington Gas' results of operations, financial condition and cash flows.

Washington Gas is incurring significant capital expenditures in connection with the rehabilitation of a portion of its natural gas distribution system in Prince George's County, Maryland. If it is unable to recover these costs, this could have a significant adverse effect on Washington Gas' financial condition, results of operations and cash flows.

Based on scientific evidence from an international consulting firm, it is our opinion that the introduction of gas from the Dominion Cove Point LNG terminal into Washington Gas' natural gas distribution system caused the reduction in sealing force of the rubber seals within certain mechanical couplings on Washington Gas' distribution system in a portion of Prince George's County, Maryland. Therefore, we have concluded that this reduction in sealing force led to a significant increase in leaks in fiscal year 2005 in the affected area of Prince George's County, Maryland.

Given the increase in the number of natural gas leaks, Washington Gas began to replace gas service lines and rehabilitate gas mains that contain the applicable mechanical couplings in the affected area of the distribution system in Prince George's County (the rehabilitation project), with a projected date of completion by the end of December 2007. The original estimate of the cost of the

rehabilitation project is $144 million; however, actual costs incurred for the work associated with this project could differ materially from this cost estimate. If Washington Gas is unable to recover from customers through the regulatory process all or some of these costs and its authorized rate of return on these costs, this could have a significant adverse effect on Washington Gas' financial condition, results of operations and cash flows.

The receipt of additional amounts of gas from the Dominion Cove Point LNG terminal into Washington Gas' natural gas distribution system may result in higher operating expenses and capital expenditures which may have a material adverse effect on its financial condition, results of operations and cash flows.

On June 16, 2006, the FERC issued an order authorizing the request of Dominion Resources, Inc., the owner of the Dominion Cove Point LNG facility, to expand the capacity and output of its Cove Point terminal. This expansion would result in a substantial increase in the volume of Cove Point gas introduced into Washington Gas' distribution system in areas that have distribution and service lines constructed of similar materials and in a similar manner to those in the affected area of Prince George's County. We estimate that this increase would occur in fiscal year 2008 or thereafter. The increased volume of Cove Point gas that will flow into Washington Gas' distribution system may cause additional leaks on couplings in its system (except in the area of Prince George's County, Maryland that is undergoing the rehabilitation project).

We are taking actions to prepare for the receipt of increased volumes of gas from the Cove Point terminal. Washington Gas constructed the facilities necessary to treat the gas from the Cove Point terminal that is exclusively received at the gate station that serves the affected area of Prince George's County, Maryland where the increase in gas leaks has been observed. Additionally, Washington Gas has begun the planning necessary to construct two additional treatment facilities at gate stations in anticipation that more gas from the Cove Point terminal may begin flowing into the interconnected pipelines and, therefore, into other areas of its distribution system. However, we have not gathered enough evidence yet to conclude that the treatment of the Cove Point gas received into Washington Gas' distribution system will be completely effective in preventing additional leaks or retarding the rate at which additional leaks may occur in the gas distribution system if additional volumes from the Cove Point terminal are introduced. Also, construction of these additional facilities may not be timely, permitted or feasible. If the facilities are constructed, the treatment of the Cove Point gas may not be effective or only partially effective in preventing additional leaks on couplings in the gas distribution system. If the planned actions of treating the Cove Point gas are not successful or only partially effective in preventing additional leaks on couplings, and if we are not able to determine a satisfactory alternative solution on a timely basis, additional operating expenses and capital expenditures may be necessary to contend with the receipt of increased volumes of gas from the Cove Point LNG terminal into Washington Gas' distribution system. These additional expenditures may not be recoverable or may not be recoverable on a timely enough basis from customers, or other parties. Therefore, these conditions could have a material adverse effect on Washington Gas' financial condition, results of operations and cash flows.

Changes in the relative prices of alternative forms of energy may strengthen or weaken the competitive position of Washington Gas' natural gas delivery service. If the competitive position of natural gas service weakens, it may reduce the number of natural gas customers in the future and negatively affect Washington Gas' future cash flows and net income.

The price of natural gas delivery service that Washington Gas provides competes with the price of other forms of energy such as electricity, oil and propane. Changing prices of natural gas versus other sources of energy that Washington Gas competes against can cause the competitive position of our natural gas delivery service to improve or decline. A decline in the competitive position of natural gas service in relation to alternative energy sources can lead to fewer natural gas customers, lower volumes of natural gas delivered, lower cash flows and lower net income.

A decline in the economy or significant increases in interest rates may reduce revenues or increase costs.

A decline in the economy of the region in which Washington Gas operates, or a significant increase in interest rates to be paid by potential purchasers of new homes, might adversely affect Washington Gas' ability to grow its customer base at the same rate it has grown in the past. An increase in the interest rates Washington Gas pays without the recognition of the higher cost of debt incurred by it in the rates charged to its customers would adversely affect Washington Gas' future earnings and cash flows.

Washington Gas' inability to access capital or to access capital cost effectively may adversely affect its business. A downgrade in Washington Gas' credit ratings could increase its borrowing costs.

Washington Gas' ability to obtain adequate and cost effective capital depends largely on its credit ratings, which are greatly affected by Washington Gas' financial performance and the liquidity of financial markets. A downgrade in Washington Gas' current credit ratings could affect its access to capital markets, as well as its cost of capital and ability to earn its authorized rate of return.

As a wholly owned subsidiary of WGL Holdings, Washington Gas depends solely on WGL Holdings to raise new common equity capital and contribute that common equity to Washington Gas. If WGL Holdings is unable to raise common equity capital, this also could adversely affect Washington Gas' credit ratings and its ability to earn its authorized rate of return.

Washington Gas' risk management strategies and related hedging activities may not be effective in managing its risks, and may result in additional liability for which rate recovery may be disallowed and cause increased volatility in its earnings.

Washington Gas' business requirements expose it to commodity price, weather, credit and interest-rate risks. Washington Gas attempts to manage its exposure to these risks by hedging, setting risk limits and employing other risk management tools and procedures. Risk management activities may not be as effective as planned, and cannot eliminate all of its risks. Washington Gas also may be exposed to additional liability should the anticipated revenue recovery of costs or losses incurred with certain of these risk management activities be subsequently excluded from the determination of revenues by a regulator.

Washington Gas' facilities and operations could be targets of acts of terrorism.

Washington Gas' natural gas distribution, transmission and storage facilities may be targets of terrorist activities that could result in a disruption of its ability to meet customer requirements. Terrorist attacks may also disrupt capital markets and Washington Gas' ability to raise capital. A terrorist attack on Washington Gas' facilities or those of its natural gas suppliers or customers could result in a significant decrease in revenues or a significant increase in repair costs, which could adversely affect its results of operations, financial position and cash flows.

WASHINGTON GAS ENERGY SERVICES, INC.

WGEServices' business, earnings and cash requirements are highly weather sensitive and seasonal.

WGEServices, our retail energy-marketing subsidiary, is weather sensitive and seasonal, with a significant portion of revenues derived from the sale of natural gas to retail customers for space heating during the winter months, and from the sale of electricity to customers for cooling during the summer months. Weather conditions directly influence the volume of natural gas and electricity delivered to customers. Weather conditions can also affect the short-term pricing of energy supplies that WGEServices may need to procure to meet the needs of its customers. Deviations in weather from normal levels and the seasonal nature of WGEServices' business can create large variations in earnings and short-term cash requirements.

The ability of WGEServices to meet customers' natural gas and electricity requirements may be impaired if contracted supply is not available or delivered in a timely manner.

Sufficient deliverability of natural gas and electric supplies to serve the demand of WGEServices' customers is dependent upon the ability of natural gas producers, pipeline gatherers, natural gas processors, interstate pipelines, suppliers of electricity and regional electric transmission operators to deliver the respective commodities. If WGEServices is unable to secure adequate supply in a timely manner, either due to the failure of its suppliers to deliver the contracted commodity or the inability to secure additional quantities during significant abnormal weather conditions, it may be unable to meet its customer requirements. Such inability to meet its delivery obligations to customers could result in WGEServices experiencing defaults on contractual terms with its customers, penalties and financial damage payments, the loss of certain licenses and operating authorities, and/or a need to return customers to the bundled services of regulated utility companies, such as Washington Gas.

The risk management strategies and related hedging activities of WGEServices may not be effective in managing risks and may cause increased volatility in its earnings.

WGEServices is exposed to commodity price risk to the extent its natural gas and electricity purchases are not closely matched to its sales commitments in terms of volume and pricing. WGEServices attempts to manage its exposure to commodity price risk, as well as its exposure to weather and credit risks by hedging, setting risk limits, and employing other risk management tools and procedures. These risk management activities may not be as effective as planned, and cannot eliminate all of WGEServices' risks.

Significant increases in interest rates may increase costs.

WGEServices depends on short-term debt to finance its accounts receivable and storage gas inventories. Working capital requirements vary significantly during the year, and we finance these requirements primarily through the issuance of commercial

paper and unsecured short-term bank loans by WGL Holdings. The results of operations of WGEServices would be adversely affected if short-term interest rates rose or if we were unable to access capital in a cost-effective manner.

WGEServices is dependent on guarantees from WGL Holdings.

The ability of WGEServices to purchase natural gas and electricity from suppliers is dependent upon guarantees issued on its behalf by WGL Holdings. Should WGL Holdings not renew such guarantees after the effective date of their cancellation, the ability of WGEServices to make commodity purchases at reasonable prices would be impaired, adversely affecting its results of operations, financial position and cash flows.

Competition may negatively affect WGEServices.

WGEServices competes with other non-regulated retail suppliers of natural gas and electricity, as well as with the commodity rate offerings of electric and gas utilities. Increases in competition including utility commodity rate offers that are below prevailing market rates may cause a loss of sales volumes or a reduction of growth opportunities for WGEServices that could adversely affect its results of operations and cash flows.

Regulatory developments may negatively affect WGEServices.

The regulations that govern the conduct of competitive energy markets are subject to change as the result of legislation or regulatory proceedings. Changes in these regulatory rules could reduce customer growth opportunities for WGEServices, or could reduce the profit opportunities associated with certain groups of existing or potential new customers and, thereby, adversely affect its results of operations and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

At September 30, 2006, we provided services in various areas of Virginia, the District of Columbia and Maryland, and held certificates of convenience and necessity, licenses and permits necessary to maintain and operate their respective properties and businesses. The regulated utility segment is the only segment where property, plant and equipment is a significant asset.

Property, plant and equipment is stated at original cost, including labor, materials, taxes and overhead costs incurred during the construction period. Washington Gas calculates depreciation applicable to its utility gas plant in service primarily using a straight-line method over the estimated remaining life of the plant. The composite depreciation and amortization rate of the regulated utility was 3.44 percent during fiscal year 2006, and 3.48 percent during fiscal years 2005 and 2004, which included an allowance for estimated accrued non-legal asset removal costs (see Note 1 of the Notes to Consolidated Financial Statements).

At September 30, 2006, Washington Gas had approximately 642 miles of transmission mains, 11,813 miles of distribution mains, and 13,346 miles of distribution services. Washington Gas has the storage capacity for approximately 15 million gallons of propane for peak shaving.

Washington Gas owns approximately 40 acres of land and a building (built in 1970) at 6801 Industrial Road in Springfield, Virginia. The Springfield site performs both operating and certain administrative functions of the utility. Washington Gas also holds title to land and buildings used as substations for its utility operations.

Washington Gas also has peaking facilities to enhance deliverability in periods of peak demand in the winter that consist of propane air plants in Springfield, Virginia (Ravensworth Station), and Rockville, Maryland (Rockville Station). Hampshire operates an underground natural gas storage field in Hampshire County, West Virginia. Hampshire accesses the storage field through 12 storage wells that are connected to an 18-mile pipeline gathering system. Hampshire also operates a compressor station for injection of gas into storage. For pipeline year 2007, we estimate that the Hampshire storage facility has the capacity to supply approximately 2.2 billion cubic feet of natural gas to Washington Gas' system for meeting seasonal demands.

Washington Gas owns a 12-acre parcel of land located in Southeast Washington, D.C. Washington Gas entered into an agreement with a national developer to develop this land in phases. Washington Gas selected the developer to design, execute and manage the various phases of the development. The development, Maritime Plaza, is intended to be a mixed-use commercial project that will be implemented in five phases. The first two phases have been developed, with Washington Gas retaining a 99-year ground lease on each phase. See the section entitled *"Environmental Matters"* under Item 1 of this report for additional information regarding this development.

Facilities utilized by our corporate headquarters, as well as by the retail energy-marketing and commercial HVAC segments, are located in the Washington, D.C. metropolitan area and are leased.

The Mortgage of Washington Gas dated January 1, 1933 (Mortgage), as supplemented and amended, securing any First Mortgage Bonds (FMBs) it issues, constitutes a direct lien on substantially all property and franchises owned by Washington Gas other than a small amount of property that is expressly excluded. At September 30, 2006 and 2005, no debt was outstanding under the Mortgage.

Washington Gas executed a supplemental indenture to its unsecured Medium-Term Note (MTN) Indenture on September 1, 1993, providing that Washington Gas will not issue any FMBs under its Mortgage without securing all MTNs with all other debt secured by the Mortgage.

ITEM 3. LEGAL PROCEEDINGS

None.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages and positions of the executive officers of the registrants at October 31, 2006, are listed below along with their business experience during the past five years. The age of each officer listed is as of the date of filing of this report. There is no family relationship among the officers.

Unless otherwise indicated, all officers have served continuously since the dates indicated, and all positions are executive officers listed with Washington Gas Light Company.

Executive Officers

Name, Age and Position with the Registrants	Date Elected or Appointed
Vincent L. Ammann, Jr., Age 47 (1,2)	
Vice President and Chief Financial Officer	September 30, 2006
Vice President and Chief Financial Officer of WGL Holdings, Inc.	September 30, 2006
Vice President—Finance	October 1, 2005
Vice President—Finance of WGL Holdings, Inc.	October 1, 2005
Assistant to the Chief Financial Officer	March 29, 2004
Elizabeth M. Arnold, Age 54 (1)	
Vice President—Strategy	January 24, 2004
Vice President—Strategy of WGL Holdings, Inc.	January 24, 2004
Vice President—Strategy and Non-Utility Businesses of WGL Holdings, Inc.	October 31, 2000
Vice President—Strategy and Non-Utility Businesses	July 3, 2000
Beverly J. Burke, Age 55 (1)	
Vice President and General Counsel	July 1, 2001
Vice President and General Counsel of WGL Holdings, Inc.	July 1, 2001
Gautam Chandra, Age 40 (1,3)	
Vice President—Performance Improvement	October 1, 2005
Vice President—Performance Improvement and Non-Utility Operations of WGL Holdings, Inc.	October 1, 2005
Division Head—Finance Support and Non-Utility Businesses	January 5, 2004
Division Head—Achieving Operational Excellence	December 12, 2002
Adrian P. Chapman, Age 49	
Vice President—Operations, Regulatory Affairs and Energy Acquisition	October 1, 2005
Vice President—Regulatory Affairs and Energy Acquisition	March 31, 1999
James H. DeGraffenreidt, Jr., Age 53 (1)	
Chairman of the Board and Chief Executive Officer	October 1, 2001
Chairman of the Board and Chief Executive Officer of WGL Holdings, Inc.	October 1, 2001
Lauren A. Foley, Age 41 (4)	
Vice President—Consumer Services	October 13, 2006
Division Head—Customer Services	July 15, 2002
Shelley C. Jennings, Age 58 (1)	
Treasurer of WGL Holdings, Inc.	January 13, 2000
Treasurer	March 31, 1999
Wilma Kumar-Rubock, Age 58	
Vice President and Chief Information Officer	October 1, 2001
Terry D. McCallister, Age 50 (1)	
President and Chief Operating Officer	October 1, 2001
President and Chief Operating Officer of WGL Holdings, Inc.	October 1, 2001

Executive Officers

Name, Age and Position with the Registrants	Date Elected or Appointed
Mark P. O'Flynn, Age 56 (1,5)	
Controller	February 18, 2002
Controller of WGL Holdings, Inc.	February 18, 2002
Douglas V. Pope, Age 61 (1)	
Secretary of WGL Holdings, Inc.	January 13, 2000
Secretary	July 25, 1979
Roberta W. Sims, Age 52	
Vice President—Corporate Relations and Communications	January 31, 1996
Douglas A. Staebler, Age 46 (6)	
Vice President—Engineering and Construction	October 31, 2006
Division Head—Engineering	July 25, 2005
William Zeigler, Jr., Age 61 (7)	
Vice President—Human Resources and Organizational Development	February 1, 2004
Division Head—Organizational Development	February 10, 2003

(1) Executive Officer of both WGL Holdings, Inc. and Washington Gas Light Company.

(2) Mr. Ammann was previously employed by Southern Connecticut Gas Company and Connecticut Natural Gas Corporation, subsidiaries of Energy East Corporation, where he served as Senior Vice President, Finance and Administration. Prior to working for Southern Connecticut Gas Company, Mr. Ammann held various audit and consulting positions for Deloitte & Touche in Washington, D.C. and Detroit, Michigan.

(3) Mr. Chandra was previously employed by Cambridge Strategy Group, LLC where he served as Managing Director. Prior to working for Cambridge Strategy Group, LLC, Mr. Chandra was the President & CEO of SmartEnergy, Inc.

(4) Ms. Foley was previously employed by Nstar Electric and Gas where she held various positions in customer service operations, financial controls and auditing, project management, and regulatory matters.

(5) Mr. O'Flynn has more than 30 years of experience in various finance positions with natural gas and electric utilities. He has previous experience as a chief financial officer, controller and treasurer of utility companies that were SEC registrants.

(6) Mr. Staebler was previously employed by NUI Corporation—Elizabethtown Gas where he held various positions in engineering, operations and construction and maintenance.

(7) Mr. Zeigler was previously employed by Ernst & Young LLP (E&Y) where he served as National Director of Leadership and Organizational Change. Prior to joining E&Y, Mr. Zeigler was Senior Director, Organization Development and Training with Praxair, Inc. of Danbury, Connecticut.

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

At October 31, 2006, WGL Holdings had 14,951 common shareholders of record. During fiscal years 2006 and 2005, WGL Holdings' common stock was listed for trading on the New York Stock Exchange and was shown as "WGL Hold" or "WGL Hldgs" in newspapers. We did not purchase any of our outstanding common stock during fiscal years 2006 and 2005. The table below shows quarterly price ranges and quarterly dividends paid for fiscal years ended September 30, 2006 and 2005.

Common Stock Price Range and Dividends Paid

	High	Low	Dividends Paid Per Share	Dividend Payment Date
Fiscal Year 2006				
Fourth quarter	$31.82	$28.44	$0.3375	08/1/06
Third quarter	30.74	27.04	0.3375	05/1/06
Second quarter	31.49	29.59	0.3325	02/1/06
First quarter	32.88	28.86	0.3325	11/1/05
Fiscal Year 2005				
Fourth quarter	$34.79	$31.39	$0.3325	08/1/05
Third quarter	33.96	29.66	0.3325	05/1/05
Second quarter	31.97	28.85	0.3250	02/1/05
First quarter	31.43	27.71	0.3250	11/1/04

ITEM 6. SELECTED FINANCIAL DATA[a]

(In thousands, except per share data)

Years Ended September 30,	**2006**	2005	2004	2003	2002
SUMMARY OF EARNINGS					
Operating Revenues					
Utility	**$1,622,510**	$1,379,390	$1,267,948	$1,301,057	$ 925,131
Non-utility	**1,015,373**	783,953	798,495	742,508	636,859
Total operating revenues	**$2,637,883**	$2,163,343	$2,066,443	$2,043,565	$1,561,990
Income from continuing operations	**$ 94,694**	$ 106,072	$ 99,595	$ 114,463	$ 37,183
Net income (applicable to common stock)	**$ 87,578**	$ 103,493	$ 96,637	$ 112,342	$ 39,121
Earnings per average common share					
Basic:					
Income from continuing operations	**$ 1.94**	$ 2.18	$ 2.05	$ 2.36	$ 0.77
Net income (applicable to common stock)	**$ 1.80**	$ 2.13	$ 1.99	$ 2.31	$ 0.81
Diluted:					
Income from continuing operations	**$ 1.94**	$ 2.16	$ 2.04	$ 2.35	$ 0.76
Net income (applicable to common stock)	**$ 1.79**	$ 2.11	$ 1.98	$ 2.30	$ 0.80
CAPITALIZATION—YEAR-END					
Common shareholders' equity	**$ 921,807**	$ 893,992	$ 853,424	$ 818,218	$ 766,403
Washington Gas Light Company Preferred stock	**28,173**	28,173	28,173	28,173	28,173
Long-term debt, excluding current maturities	**576,139**	584,150	590,156	636,614	667,852
Total capitalization	**$1,526,119**	$1,506,315	$1,471,753	$1,483,005	$1,462,428
OTHER FINANCIAL DATA					
Total assets—year-end	**$2,791,406**	$2,601,081	$2,506,254	$2,436,680	$2,340,715
Property, plant and equipment-net—year-end	**$2,067,895**	$1,969,016	$1,914,420	$1,873,446	$1,830,538
Capital expenditures					
Accrual basis[b]	**$ 161,496**	$ 124,014	$ 113,285	$ 129,011	$ 161,970
Adjustments for non-cash items	**(1,739)**	(11,246)	(4,897)	462	1,217
Cash basis	**$ 159,757**	$ 112,768	$ 108,388	$ 129,473	$ 163,187
Long-term obligations—year-end	**$ 576,139**	$ 584,150	$ 590,156	$ 636,614	$ 667,852
COMMON STOCK DATA					
Annualized dividends per share	**$ 1.35**	$ 1.33	$ 1.30	$ 1.28	$ 1.27
Dividends declared per share	**$ 1.3450**	$ 1.3225	$ 1.2950	$ 1.2775	$ 1.2675
Closing price	**$ 31.34**	$ 32.13	$ 28.26	$ 27.58	$ 23.91
Book value per share—year-end	**$ 18.86**	$ 18.36	$ 17.54	$ 16.83	$ 15.78
Return on average common equity	**9.6%**	11.8%	11.6%	14.2%	5.0%
Dividend yield on book value	**7.2%**	7.2%	7.4%	7.6%	8.0%
Dividend payout ratio	**74.7%**	62.1%	65.1%	55.3%	156.5%
Shares outstanding—year-end (thousands)	**48,878**	48,704	48,653	48,612	48,565
UTILITY GAS SALES AND DELIVERIES *(thousands of therms)*					
Gas sold and delivered					
Residential firm	**593,594**	625,251	629,728	648,809	509,243
Commercial and industrial					
Firm	**213,997**	222,587	226,407	239,628	193,917
Interruptible	**6,185**	7,809	7,626	12,163	10,646
Total gas sold and delivered	**813,776**	855,647	863,761	900,600	713,806
Gas delivered for others					
Firm	**403,812**	434,099	454,549	496,889	346,910
Interruptible	**251,003**	279,924	268,483	257,799	277,367
Electric generation	**108,315**	73,874	41,052	67,245	169,210
Total gas delivered for others	**763,130**	787,897	764,084	821,933	793,487
Total utility gas sales and deliveries	**1,576,906**	1,643,544	1,627,845	1,722,533	1,507,293
OTHER STATISTICS					
Active customer meters—year-end	**1,031,916**	1,012,105	990,062	959,922	939,291
New customer meters added	**24,693**	26,682	29,438	26,167	31,205
Degree days—actual	**3,710**	4,023	4,024	4,550	3,304
Weather percent colder (warmer) than normal	**(2.5)%**	5.9%	6.1%	19.8%	(13.4)%

[a] *On September 29, 2006, we sold all of the outstanding shares of common stock of ACI, previously reported as part of our commercial HVAC business segment. ACI has been reported as a discontinued operation of WGL Holdings and, accordingly, its operating results have been presented separately from our continuing operations for all years presented.*

[b] *Excludes Allowance for Funds Used During Construction. Includes capital expenditures accrued and capital expenditure adjustments recorded in the fiscal year.*

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

INTRODUCTION

This *Management's Discussion and Analysis of Financial Condition and Results of Operations* (Management's Discussion) analyzes the financial condition, results of operations and cash flows of WGL Holdings, Inc. (WGL Holdings) and its subsidiaries. It also includes management's analysis of past financial results and potential factors that may affect future results, potential future risks and approaches that may be used to manage them. Except where the content clearly indicates otherwise, "WGL Holdings," "we," "us" or "our" refers to the holding company or the consolidated entity of WGL Holdings and all of its subsidiaries.

Management's Discussion is divided into the following two major sections:

- **WGL Holdings**—This section describes the financial condition and results of operations of WGL Holdings and its subsidiaries on a consolidated basis. It includes discussions of our regulated and unregulated operations. The majority of WGL Holdings' operations are derived from the results of Washington Gas Light Company (Washington Gas) and, to a much lesser extent, the results of our non-utility operations.
- **Washington Gas**—This section describes the financial condition and results of operations of Washington Gas, a wholly owned subsidiary that comprises the majority of our regulated utility segment.

Both of the major sections of Management's Discussion—WGL Holdings and Washington Gas—should be read to obtain an understanding of our operations and financial performance. Management's Discussion also should be read in conjunction with the respective company's financial statements and the combined Notes to Consolidated Financial Statements.

Unless otherwise noted, earnings per share amounts are presented on a diluted basis, and are based on weighted average common and common equivalent shares outstanding. The earnings per share of any segment does not represent a direct legal interest in the assets and liabilities allocated to any one segment, but rather represents a direct equity interest in our assets and liabilities as a whole.

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EXECUTIVE OVERVIEW

Introduction

WGL Holdings, through its wholly owned subsidiaries, sells and delivers natural gas and provides a variety of energy-related products and services to customers primarily in Washington, D.C. and the surrounding metropolitan areas in Maryland and Virginia. Our core subsidiary, Washington Gas, engages in the delivery and sale of natural gas that is regulated by regulatory commissions in the District of Columbia, Maryland and Virginia. Through the wholly owned, unregulated subsidiaries of Washington Gas Resources Corporation (Washington Gas Resources), we also offer energy-related products and services. In response to changes in federal and state regulation, we offer competitively priced natural gas and electricity to customers through Washington Gas Energy Services (WGEServices), our unregulated retail energy-marketing subsidiary.

WGL Holdings has three operating segments that are described below:

- regulated utility;
- retail energy-marketing and
- commercial heating, ventilating and air conditioning (HVAC) products and services.

Transactions not specifically identifiable in one of the above three segments are accumulated and reported in the category "Other Activities."

Regulated Utility. With approximately 92 percent of our consolidated total assets, the regulated utility segment consists of Washington Gas and Hampshire Gas Company (Hampshire). Washington Gas, a wholly owned subsidiary of WGL Holdings, delivers natural gas to retail customers in accordance with tariffs approved by the regulatory commissions that have jurisdiction over Washington Gas' rates. Washington Gas also sells natural gas to customers who have not elected to purchase natural gas from unregulated third-party marketers. Washington Gas does not earn a profit or incur a loss when it sells the natural gas commodity because utility customers are charged for the natural gas commodity at the same cost that Washington Gas incurs.

Hampshire, a wholly owned subsidiary of WGL Holdings, operates an underground natural gas storage facility that is regulated by the Federal Energy Regulatory Commission (FERC). Washington Gas purchases all of the storage services of Hampshire and includes the cost of these services in the bills sent to its customers. Hampshire operates under a "pass-through" cost of service-based tariff approved by the FERC, and adjusts its billing rates to Washington Gas on a periodic basis to account for changes in its investment in utility plant and associated expenses.

Retail Energy-Marketing. The retail energy-marketing segment includes the operations of WGEServices, a wholly owned subsidiary of Washington Gas Resources. WGEServices competes with other unregulated third-party marketers by selling natural gas and electricity directly to residential, commercial and industrial customers in Maryland, Virginia, Delaware and the District of Columbia. WGEServices does not own or operate any natural gas or electric generation, production, transmission or distribution assets. Rather, it buys and resells natural gas and electricity with the objective of earning a profit through competitively-priced contracts. These commodities are delivered to retail customers through the assets owned by regulated utilities such as Washington Gas or other unaffiliated natural gas or electric utilities.

Commercial HVAC. The commercial HVAC segment includes the operations of WGESystems, a wholly owned subsidiary of Washington Gas Resources. WGESystems manages design-build and renovation projects and provides maintenance services to the commercial and government markets. WGESystems focuses on retrofitting the mechanical, electrical and energy-related systems of a large number of aging commercial and government structures, primarily in the District of Columbia and portions of Maryland and Virginia. On September 29, 2006, Washington Gas Resources sold all of the outstanding shares of common stock of its wholly owned subsidiary, American Combustion Industries, Inc. (ACI) that was previously reported as part of the commercial HVAC segment (refer to the section entitled *"Discontinued Operations"*).

Refer to the *Business* section under Item 1 of this report for a further discussion of our regulated utility and non-utility business segments. For a further discussion of our financial performance by operating segment, refer to Note 17 of the Notes to Consolidated Financial Statements.

Key Indicators of Financial Condition and Operating Performance

We have determined that the following are key indicators for monitoring our financial condition and operating performance:

Return on Average Common Equity. This measure is calculated by dividing twelve months ended net income (applicable to common stock) by average common shareholders' equity. For Washington Gas, we compare the actual return on common equity with the return on common equity that is allowed to be earned by regulators and the return on equity that is necessary for us to compensate investors sufficiently and be able to continue to attract capital.

Common Equity Ratio. This ratio is calculated by dividing total common shareholders' equity by the sum of common shareholders' equity, preferred stock and long-term debt (including current maturities). Maintaining this ratio in the mid-50 percent range affords us financial flexibility and access to long-term capital at relatively low costs. Refer to the section entitled *"Liquidity and Capital Resources—General Factors Affecting Liquidity"* for a discussion of our capital structure.

PRIMARY FACTORS AFFECTING WGL HOLDINGS AND WASHINGTON GAS

The following is a summary discussion of the primary factors that affect the operations and/or financial performance of our regulated and unregulated businesses. Refer to the section entitled *"Business"* under Item 1 of this report for a more detailed discussion of these and other related factors that affect the operations and/or financial performance of WGL Holdings and Washington Gas.

Weather Conditions and Weather Patterns

Washington Gas' operations are weather sensitive, with a significant portion of its revenues derived from the delivery of natural gas to residential and commercial heating customers during the winter heating season. Generally, weather conditions directly influence the volume of natural gas delivered by Washington Gas. However, weather patterns may become erratic during "shoulder" months within our fiscal year in which Washington Gas is going into or coming out of the primary portion of its winter heating season. During the shoulder months within quarters ending December 31 (particularly in October and November) and within quarters ending June 30 (particularly in April and May), customer heating usage may not correlate highly with the level of recorded heating degree days during those months when weather patterns experienced are not consistently cold or warm.

Washington Gas' rates are determined on the basis of expected normal weather conditions. Prior to October 1, 2005, Washington Gas did not have a ratemaking provision in any of its jurisdictions that allowed for revenues to be adjusted for the difference between actual weather conditions in a particular year and the expected normal weather conditions that are used to establish rates. Consequently, deviations in weather from normal levels affected Washington Gas' financial performance. Washington

Gas managed weather risk for all jurisdictions with a weather insurance policy designed to protect against 50 percent of the negative financial effects of warmer-than-normal weather. That policy expired on September 30, 2005.

Commencing in fiscal year 2006, Washington Gas implemented new weather protection strategies designed to provide full protection from the negative financial effects of warmer-than-normal weather. Effective October 1, 2005, Washington Gas implemented a Revenue Normalization Adjustment (RNA) billing mechanism in Maryland. Approved by the Public Service Commission of Maryland (PSC of MD), the RNA is a mechanism designed to stabilize the level of net revenues collected from Maryland customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels and certain other factors such as customer conservation. Deliveries to Maryland customers represent approximately 40 percent of therms delivered by Washington Gas. As Washington Gas currently has no similar ratemaking provisions in the District of Columbia or Virginia, the utility is utilizing a new three-year weather insurance policy in the District of Columbia that became effective October 1, 2005, and weather derivatives in Virginia. Refer to the section entitled *"Market Risk—Weather Risk"* for a further discussion of our weather protection strategies.

While the use of weather insurance and a weather derivative in the District of Columbia and Virginia, respectively, were effective in providing full protection from the effects of warmer-than-normal weather in those jurisdictions during fiscal year 2006, our intent is to obtain this protection through ratemaking provisions in these two jurisdictions similar to the RNA that was implemented in Maryland. On September 15, 2006, Washington Gas filed an application with the State Corporation Commission of Virginia (SCC of VA) requesting, among other things, to implement a tariff provision for an RNA billing mechanism in Virginia. A final order by the SCC of VA on this and all other requests included in the application is pending.

The financial results of our energy-marketing subsidiary, WGEServices, also are affected by deviations in weather from normal levels. Since WGEServices sells both natural gas and electricity, WGEServices' financial results may fluctuate due to deviations in weather from fiscal year to fiscal year during the winter heating and summer cooling seasons.

Regulatory Environment and Regulatory Decisions

Washington Gas is regulated by the Public Service Commission of the District of Columbia (PSC of DC), the PSC of MD and the SCC of VA. Hampshire is regulated by the FERC. These regulatory commissions set the rates in their respective jurisdictions that Washington Gas can charge customers for its rate-regulated services. Changes in these rates as ordered by regulatory commissions affect Washington Gas' financial performance.

Washington Gas expects that regulatory commissions will continue to set the prices and terms for delivery service that give it an opportunity to earn a just and reasonable rate of return on the capital invested in its distribution system and to recover reasonable operating expenses.

Gas Supply and Pipeline Transportation and Storage Capacity

Natural Gas Supply and Capacity Requirements. Washington Gas is responsible for acquiring both sufficient natural gas supplies and interstate pipeline and storage capacity to meet customer requirements. As such, Washington Gas must contract for reliable and adequate delivery capacity to its distribution system, while considering the dynamics of the interstate pipeline and storage capacity market, its own on-system natural gas peaking facilities, as well as the characteristics of its customer base.

Depleting pipeline and storage capacity is a business issue for local distribution companies, such as Washington Gas. Washington Gas, whose customer base has grown at an annual rate of approximately two percent, must manage this issue. This rate of growth is expected to continue. To help maintain the adequacy of pipeline and storage capacity for its growing customer base, Washington Gas has contracted with various interstate pipeline and storage companies for the acquisition of additional existing capacity, as well as the construction of new capacity, for firm transportation and storage services to Washington Gas. These capacity expansion projects are expected to be placed into service during fiscal years 2007-2010. Washington Gas will continue to monitor other opportunities to acquire or participate in obtaining additional pipeline and storage capacity that will improve or maintain the high level of service expected by its customer base.

Gulf Coast Natural Gas Supply Issues. During the late summer of 2005, immediately prior to the 2005-2006 winter heating season, the Gulf Coast region experienced a major disruption of natural gas production and processing due to hurricanes Katrina, Rita and Wilma. These natural gas production and processing disruptions resulted in a significant reduction of natural gas available to be delivered from the Gulf Coast region. Given the recovery of available supplies from the Gulf Coast region following the hurricanes,

coupled with the availability of natural gas supply from alternative production areas, Washington Gas was able to meet its customers' daily demand for natural gas during the 2005-2006 winter heating season. Storage gas inventory balances were maintained at adequate operational levels throughout the heating season. Since hurricanes Katrina, Rita and Wilma, Washington Gas has modified the composition of its natural gas portfolio to include a significantly higher percentage of natural gas supply that is produced from sources outside of the Gulf Coast region. The diversification of its natural gas portfolio will help Washington Gas to meet customer demand despite unforeseen future supply issues that may arise similar to those resulting from the weather events in the Gulf Coast region.

WGEServices purchases a portion of its natural gas supply from the Gulf Coast region. Purchase commitments from certain of WGEServices' Gulf Coast-based natural gas suppliers were interrupted by the supply shortage in the Gulf Coast region in the immediate aftermath of the hurricanes during the fall 2005 season. During the 2005-2006 winter heating season, all of WGEServices' contracted natural gas supplies from the Gulf Coast region flowed as contracted, and WGEServices met its customers' daily demand for natural gas and achieved its required storage inventory balances. In meeting its future natural gas supply needs, WGEServices expects to continue to rely on a diverse set of supply sources, including city-gate delivered supplies, natural gas in storage and liquefied natural gas (LNG) from the Dominion Cove Point (Dominion or Cove Point) LNG terminal.

Volatility of Natural Gas Prices. As a result of market concerns about the sufficiency of the supply of natural gas, the hurricanes in the Gulf Coast region and other factors during the 2005-2006 winter heating season, the price of the natural gas commodity paid by Washington Gas' customers rose sharply from levels experienced during the prior year's winter heating season. In fiscal year 2006, higher natural gas prices increased customers' bills dramatically. Under its regulated gas cost recovery mechanisms, Washington Gas records cost of gas expense equal to the cost of gas recovered in revenues from customers. An increase in the cost of gas due to an increase in the purchase price of the natural gas commodity generally has no direct effect on Washington Gas' net income. However, its net income was reduced in fiscal year 2006 primarily due to higher expenses for uncollectible customer accounts, as well as lower natural gas consumption caused by customer conservation in Virginia and the District of Columbia where these adverse effects on earnings are not addressed through regulatory mechanisms. The RNA and other regulatory mechanisms in Maryland neutralize these effects on Washington Gas' revenue and net income. Increases in the price of natural gas also can affect our operating cash flows, as well as the competitiveness of natural gas as an energy source.

WGEServices also may be negatively affected by the indirect effects of significant increases in the wholesale price of natural gas such as those that resulted from the Gulf Coast natural gas supply shortage. WGEServices' risk management policies and procedures are designed to minimize the risk that WGEServices' natural gas purchases and the related sales commitments do not closely match (refer to the section entitled *"Market Risk"* for a further discussion of Washington Gas' and WGEServices' mitigation of commodity price risk). Higher natural gas prices, however, may increase the costs associated with uncollectible accounts, borrowing costs, certain fees paid to public service commissions and other costs. To the extent that these costs cannot be recovered from retail customers in higher rates due to competitive factors, WGEServices' operating results would be negatively affected.

Changes in Natural Gas Consumption. Natural gas supply requirements may be affected by changes in natural gas consumption by customers. Natural gas usage per customer may decline as customers change their consumption patterns in response to: *(i)* more volatile and higher natural gas prices, as discussed above, and *(ii)* customers' replacement of older, less efficient gas appliances with more efficient appliances. In each jurisdiction in which Washington Gas operates, changes in customer usage profiles have been reflected in recent rate case proceedings where rates have been adjusted to reflect current customer usage. In both the District of Columbia and Virginia jurisdictions, changes in customer usage by existing customers that occur subsequent to these recent rate case proceedings will have the effect of reducing revenues, which is offset by the favorable effect of adding new customers. Effective October 1, 2005, pursuant to an RNA mechanism approved by the PSC of MD, changes in customer usage by existing customers that occur subsequent to recent rate case proceedings in the Maryland jurisdiction generally will not reduce revenues, but rather will have the effect of stabilizing the level of delivery charge revenues received from customers on a monthly basis. On September 15, 2006, Washington Gas requested approval from the SCC of VA of a similar RNA mechanism to be put in place in the Virginia jurisdiction that would also stabilize rather than reduce revenues (refer to the section entitled *"Jurisdictional Rates and Regulatory Matters"* under Item 1 of this report).

Electricity Supply

Customer choice programs for electric customers are available in each jurisdiction in which WGEServices operates. Similar to the natural gas industry, electric customers participating in these programs may choose either to continue purchasing bundled electricity service from their local electric distribution utility or to purchase electricity from an unregulated third-party marketer.

Electric customers grew 75 percent in fiscal year 2006 when compared to the end of the prior fiscal year. This customer growth was principally the result of new competitive opportunities that emerged near the end of the third quarter of fiscal year 2006 due to sharp increases in competing rates offered by electric utilities in Maryland and Delaware. In other locations, however, future opportunities to add new electric customers may continue to be limited by the relationship between electric Standard Offer Service (SOS) rates offered by local electric utilities and market prices for electricity. Certain SOS rates in WGEServices' market area continue to be below current market prices. In certain cases, electric utilities have entered into wholesale contracts to supply their SOS customers, prior to an increase in fuel prices required to generate electricity. In other cases, electric utilities continue to provide service under previously established rates that are capped. Refer to the section entitled "*Market Risk—Price Risk Related to the Retail Energy-Marketing Segment*" for a further discussion of WGEServices' electricity supply.

Maintaining the Safety and Reliability of the Natural Gas Distribution System

Maintaining and improving the public safety and reliability of Washington Gas' natural gas distribution system is our highest priority that benefits both customers and investors through lower costs and improved customer service. Washington Gas continually refines its safety practices, with a particular focus on design, construction, maintenance, operation, replacement, inspection and monitoring practices. Operational issues affecting the public safety and reliability of Washington Gas' natural gas distribution system that are not addressed within a timely and adequate manner could significantly and adversely affect our future earnings and cash flows, as well as result in a loss of customer confidence. Washington Gas is responding to its operational issues in a timely and adequate manner, and has the financial resources necessary to address these issues due to its current strong cash position, and the financing options it has available. Refer to the section entitled *"Contractual Obligations, Off-Balance Sheet Arrangements and Other Commercial Commitments—Operating Issues in Prince George's County, Maryland"* for a discussion of an operational issue.

Competitive Environment

Washington Gas. Washington Gas faces competition based on customers' preference for natural gas compared to other energy products, and the comparative prices of those products. The most significant product competition occurs between natural gas and electricity in the residential market. Changes in the competitive position of natural gas relative to electricity and other energy products have the potential of causing a decline in the number of natural gas customers added in future years. At the present time, Washington Gas has seen no significant evidence that changes in the competitive position of natural gas has contributed to such a decline.

The residential market generates a significant portion of Washington Gas' net income. In its service territory, Washington Gas continues to attract the majority of the new residential construction market. Consumers' continuing preference for natural gas allows Washington Gas to maintain a strong market presence.

In each of the jurisdictions served by Washington Gas, regulators and utilities have implemented customer choice programs. These programs allow customers the choice of purchasing their natural gas and/or electric commodity from unregulated third-party marketers, rather than purchasing these commodities as part of a bundled service from the local utility. When customers choose to purchase their natural gas commodity from unregulated third-party marketers, there is no effect on Washington Gas' net income since Washington Gas charges its customers the cost of gas without any mark-up.

Notwithstanding the regulatory mechanisms that protect Washington Gas from the adverse impact of customer choice programs, Washington Gas continues to be obligated to purchase commodity, transportation, storage and peaking services from interstate pipeline companies under long-term capacity contracts that were entered into to support Washington Gas' expected merchant function requirements at the time these contracts were executed. In the District of Columbia and Maryland, unregulated third-party marketers may utilize their own capacity resources, rather than those of Washington Gas, to serve new customers who shift from the utility to third-party marketers in response to competitive offers or regulatory incentives. Large shifts in customers to these

third-party marketers could potentially impact the cost of the natural gas commodity billed to the remaining sales customers of Washington Gas. To minimize the cost risk associated with these obligations, Washington Gas executes a strategy that focuses on:

- managing efficiently its supply portfolio and the terms of its long-term contracts in order to balance its sales, delivery and supply obligations;
- maintaining cost recovery mechanisms in all jurisdictions related to the potentially stranded costs of the natural gas commodity;
- recovering from unregulated third-party marketers: *(i)* 100 percent of the cost of the storage and peak shaving capacity that Washington Gas dedicates to serving unbundled service customers who purchase their natural gas from a third-party marketer and *(ii)* a portion of Washington Gas' costs of transportation capacity and
- maximizing the value of contractual assets by entering into contracts with unregulated wholesale third-party marketers that make use of the utility's firm storage and transportation rights to meet its city gate delivery needs, and to make off-system sales when such storage and transportation rights are under-utilized. Washington Gas also self-manages a small portion of these type assets.

WGEServices. Our unregulated retail energy-marketing subsidiary, WGEServices, competes with other unregulated third-party marketers to sell the natural gas and electric commodity to customers. Marketers of these commodities compete largely on price, and gross margins (representing revenues less costs of energy) are relatively small. WGEServices is exposed to credit and market risks associated with both its natural gas and electric supply (refer to the sections entitled *"Credit Risk" and "Market Risk"* for a further discussion of these risk exposures and WGEServices' management of them).

Environmental Matters

We are subject to federal, state and local laws and regulations related to environmental matters. These evolving laws and regulations may require expenditures over a long timeframe to control environmental effects. It is our position that, at this time, the appropriate remediation is being undertaken at all the relevant sites. Refer to Note 14 of the Notes to Consolidated Financial Statements for a further discussion of these matters.

Industry Consolidation

In recent years, the energy industry has seen a number of consolidations, combinations, disaggregations and strategic alliances. Consolidation will present combining entities with the challenges of remaining focused on the customer and integrating different organizations. Others in the energy industry are discontinuing operations in certain portions of the energy industry or divesting portions of their business and facilities.

From time to time, we perform studies and, in some cases, hold discussions regarding utility and energy-related investments and strategic transactions with other companies. The ultimate effect on us of any such investments and transactions that may occur cannot be determined at this time.

Economic Conditions and Interest Rates

We operate in one of the fastest growing regions in the nation. The continued prosperity of this region, supported by a relatively low interest-rate environment for new housing, has allowed Washington Gas to expand its regulated delivery service customer base at a rate of growth almost twice the national industry average during the past five years. In addition, this economy has provided a robust market for our subsidiaries to market natural gas, electricity and other energy-related products and services. A downturn in the economy of the region in which we operate, or a significant increase in interest rates, might adversely affect our ability to grow Washington Gas' customer base and other businesses at the same rate they have grown in the past.

We have been operating in a relatively low interest-rate environment in the recent past as it relates to long-term debt financings. Short-term interest rates had been relatively low in relation to historical levels. However, actions and communications by the Federal Reserve in the past year have resulted in increases in short-term interest rates. A rise in interest rates without the timely recognition of the higher cost of debt in the utility rates charged by Washington Gas to its customers would adversely affect future earnings. A rise in short-term interest rates without the higher cost of debt being reflected in the prices charged to customers would negatively affect the

results of operations of our retail energy-marketing segment which depends on short-term debt to finance its accounts receivable and storage gas inventories.

Inflation/Deflation

From time to time, Washington Gas seeks approval for rate increases from regulatory commissions to help it manage the effects of inflation on its capital investment and returns. The most significant impact of inflation is on Washington Gas' replacement cost of plant and equipment. While the regulatory commissions having jurisdiction over Washington Gas' retail rates allow depreciation only on the basis of historical cost to be recovered in rates, we anticipate that Washington Gas should be allowed to recover the increased costs of its investment and earn a return thereon after replacement of the facilities occurs.

To the extent Washington Gas experiences a sustained deflationary economic environment, actual returns on invested capital could rise and exceed returns allowed by regulators in previous regulatory proceedings. Such circumstances could prompt the initiation of a regulatory review to reduce Washington Gas' revenues under its current regulatory framework.

Labor Contracts, Including Labor and Benefit Costs

Washington Gas has five labor contracts with bargaining units represented by three labor unions. Teamsters Local Union No. 96 (Local 96) is a local union affiliated with the International Brotherhood of Teamsters. Local 96 has a three-year labor contract with Washington Gas that began on June 1, 2004. The contract covers approximately 700 employees. In January 2006, the Office and Professional Employees International Union Local No. 2 (A.F.L.-C.I.O.) ratified a thirty-nine month labor contract with Washington Gas that was effective on January 1, 2006. The contract covers approximately 290 members, and replaced a previous collective bargaining agreement that was scheduled to expire on March 31, 2006. Local 96, representing union-eligible employees in the Shenandoah Gas division of Washington Gas, has a three-year labor contract with Washington Gas that began on August 1, 2004. This contract covers 23 employees. Additionally, Washington Gas has two three-year labor contracts with the International Brotherhood of Electrical Workers Local 1900 that, together, cover approximately 32 employees. Washington Gas is subject to the terms of its labor contracts with respect to operating practices and compensation matters dealing with employees represented by the various bargaining units described above.

Changes in Accounting Principles

We cannot predict the effect of potential future changes in accounting regulations or practices that have yet to be issued on our operating results and financial condition. New accounting standards could be issued by the Financial Accounting Standards Board (FASB) or the Securities and Exchange Commission (SEC) that could change the way we record and recognize revenues, expenses, assets and liabilities.

CRITICAL ACCOUNTING POLICIES

Preparation of financial statements and related disclosures in compliance with Generally Accepted Accounting Principles in the United States of America (GAAP) requires the selection and the application of appropriate technical accounting rules to the relevant facts and circumstances of our operations, as well as our use of estimates to compile the consolidated financial statements. The application of these accounting policies involves judgment regarding estimates and projected outcomes of future events, including the likelihood of success of particular regulatory initiatives, the likelihood of realizing estimates for legal and environmental contingencies, and the probability of recovering costs and investments in both the regulated utility and non-utility business segments.

We have identified the following critical accounting policies discussed below that require our judgment and estimation, where the resulting estimates have a material effect on the consolidated financial statements.

Accounting for Unbilled Revenue and Cost of Gas Recognition

For regulated deliveries of natural gas, Washington Gas reads meters and bills customers on a cycle basis. Washington Gas accrues revenues for gas that has been delivered but not yet billed at the end of an accounting period. In connection with making this accrual, Washington Gas must estimate the amount of gas that cannot be accounted for on its delivery system and must estimate the amount of the unbilled revenue by jurisdiction and customer class. Such revenues are recognized as unbilled revenues that are adjusted in subsequent periods when actual meter readings are taken. A similar computation is made for WGEServices.

Washington Gas' jurisdictional tariffs contain mechanisms that provide for the recovery of the invoice cost of gas applicable to firm customers. Under these mechanisms, Washington Gas periodically adjusts its firm customers' rates to reflect increases and decreases in the invoice cost of gas. Annually, Washington Gas reconciles the difference between the total gas costs collected from firm customers and the invoice cost of gas paid to suppliers. Washington Gas defers any excess or deficiency and either recovers it from, or refunds it to, customers over a subsequent twelve-month period.

Accounting for Regulatory Operations—Regulatory Assets and Liabilities

A significant portion of our business is subject to regulation by independent government regulators. As the regulated utility industry continues to address competitive market issues, the cost-of-service regulation used to compensate Washington Gas for the cost of its regulated operations will continue to evolve. Non-traditional ratemaking initiatives and market-based pricing of products and services could have additional long-term financial implications for us. We have relied on our projection of continued regulatory oversight of our operations in order to validate the carrying cost of Washington Gas' investment in fixed assets.

Washington Gas accounts for its regulated operations in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation,* which results in differences in the application of GAAP between regulated and unregulated businesses. SFAS No. 71 requires the recording of regulatory assets and liabilities for certain transactions that would have been treated as revenue or expense in unregulated businesses. In certain circumstances, SFAS No. 71 allows entities whose rates are determined by third-party regulators to defer costs as "regulatory" assets on the balance sheet to the extent that the entity expects to recover these costs in future rates. Similarly, SFAS No. 71 requires that certain amounts be deferred and recorded as regulatory liabilities to the extent Washington Gas expects those amounts will be refunded to customers in future rates. Future regulatory changes or changes in the competitive environment could result in WGL Holdings and Washington Gas discontinuing the application of SFAS No. 71 for some of its business and require the write-off of the portion of any regulatory asset or liability that would be no longer probable of recovery or refund. In effect, Washington Gas could be required to write off certain regulatory assets and liabilities that had been deferred on the balance sheets in prior periods, and charge or credit these amounts to income at the time it determines that the provisions of SFAS No. 71 no longer apply. If Washington Gas were required to discontinue the application of SFAS No. 71 for any of its operations, it would record an extraordinary non-cash charge or credit to income for the net book value of its regulatory assets and liabilities. Other adjustments might also be required.

Currently available facts support both the continued application of SFAS No. 71 for our regulatory activities and the conclusion that all of our regulatory assets and liabilities as of September 30, 2006 and 2005 are recoverable or refundable through the regulatory environment.

Accounting for Income Taxes

We account for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes.* Under SFAS No. 109, we recognize deferred income taxes for all temporary differences between the financial statement and tax basis of assets and liabilities at currently enacted income tax rates.

SFAS No. 109 also requires recognition of the additional deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes of Washington Gas. Regulatory assets or liabilities, corresponding to such additional deferred tax assets or liabilities, may be recorded to the extent recoverable from or payable to customers through the ratemaking process. Amounts applicable to income taxes due from and due to customers primarily represent differences between the book and tax basis of net utility plant in service.

Accounting for Contingencies

We account for contingent liabilities utilizing SFAS No. 5, *Accounting for Contingencies.* By their nature, the amount of the contingency and the timing of a contingent event are subject to our judgment of such events and our estimates of the amounts. Actual results related to contingencies may be difficult to predict and could differ significantly from the estimates included in reported earnings. In fiscal years 2006 and 2005, we were involved with regulatory contingencies with respect to rate cases in Virginia, and various legal contingencies.

On September 15, 2006, Washington Gas filed an application with the SCC of VA requesting, among other things, to increase its annual utility net revenues in Virginia. Washington Gas further requested that it be permitted to implement the newly proposed

increase in revenues on an interim basis, subject to refund, effective for services rendered on and after February 13, 2007. If Washington Gas puts the rate increase into effect on and after February 13, 2007 prior to receiving a Final Order of approval from the SCC of VA, then Washington Gas will record, as an offset to the increased revenue, a provision for rate refunds that will be derived based on our judgment of the future outcome of this rate case.

In a Final Order issued by the SCC of VA on December 18, 2003, the SCC of VA ordered, among other things, that Washington Gas perform and submit an annual earnings test to determine if it had earned in excess of its allowed rate of return on common equity for its Virginia operations. Any significant differences between ours and the VA Staff's earnings test calculations or methodology would have an effect on our operating results.

Washington Gas also is involved in matters with its local regulatory commissions related to the recovery of certain costs, including: *(i)* a proposed disallowance of certain natural gas costs previously incurred by Washington Gas and collected from Maryland customers and *(ii)* the recovery of the costs of hexane (heavy hydrocarbons or "HHCs") that Washington Gas is incurring. We have appealed to the PSC of MD the proposed disallowance of natural gas costs, and are awaiting a Final Order from the local regulatory commissions on the recovery of Washington Gas' HHC costs.

For further discussion of these regulatory matters and related contingencies, see Note 15 of the Notes to Consolidated Financial Statements.

Accounting for Derivative Instruments

We enter into forward contracts and other related transactions for the purchase of natural gas and electricity. A majority of these contracts qualify as normal purchases and sales, and are exempt from the accounting requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. Contracts that qualify as derivative instruments under SFAS No. 133 are recorded on the balance sheet at fair value. Changes in the fair value of derivative instruments subject to SFAS No. 71 are recorded as regulatory assets or liabilities, as discussed below, while changes in the fair value of derivative instruments not affected by rate regulation are reflected in income. Washington Gas also utilizes derivative instruments that are designed to minimize the risk of interest-rate volatility associated with planned issuances of Medium-Term Notes (MTNs).

Our judgment is required in determining the appropriate accounting treatment for our derivative instruments. This judgment involves various factors, including our ability to: *(i)* designate contracts and other activities as derivative instruments subject to the accounting guidelines of SFAS No. 133; *(ii)* derive the estimated fair value of our derivative instruments from period to period based on prices available from external sources and internal modeling techniques and *(iii)* determine whether or not our derivative instruments are recoverable from or refundable to customers in future periods.

Certain of our natural gas forward contracts and other derivatives that are subject to SFAS No. 133 are valued using models developed by us. These models reflect, when appropriate, derivative pricing theory, formulated market inputs and forward price projections beyond the period that prices are available from market data sources. We derived a $104,000 net fair value loss for these contracts at September 30, 2006, as compared to a net fair value gain of $23.6 million at September 30, 2005. These valuations reflect our best estimate.

As previously discussed, changes in the fair value of forward contracts and other related transactions that qualify as derivative instruments under SFAS No. 133 and subject to SFAS No. 71 are recorded as regulatory assets or liabilities since they relate to activities of Washington Gas in which costs are likely to be recovered from or refunded to customers in future periods.

Accounting for Pension and Other Post-Retirement Benefit Plans

Washington Gas maintains a qualified, trusteed, non-contributory defined benefit pension plan (qualified pension plan) covering all active and vested former employees of Washington Gas and a separate non-funded supplemental retirement plan (SERP) covering executive officers. Washington Gas also provides certain healthcare and life insurance benefits for retired employees. (The qualified pension plan, SERP and health and post-retirement plans are collectively referred to as the "Plans").

The measurement of the Plans' obligations and costs is dependent on a variety of assumptions. We consider the following assumptions to be critical to this measurement. These assumptions are derived on an annual basis with the assistance of a third party actuarial firm:

- Discount rate;
- Expected long-term return on plan assets;
- Rate of compensation increase and
- Healthcare cost trend rate.

We determine the discount rate based on the Moody's AA corporate bond yield as of September 30. We determine the expected long-term rate of return by averaging the expected earnings for the target asset portfolio. In developing the expected rate of return assumption, we evaluate an analysis of historical actual performance and long-term return projections, which gives consideration to the asset mix and anticipated length of obligation of the Plans. Historically, the expected long-term return on plan assets has been lower for the health and life benefit plan than for the qualified pension plan due to differences in the allocation of the assets in the plan trusts. We calculate the rate of compensation increase based on salary expectations for the near-term, expected inflation levels and promotional expectations. The healthcare cost trend rate is determined by working with insurance carriers, reviewing historical claims data for the health and life benefit plan, and analyzing market expectations.

The following table illustrates the effect of changing the critical actuarial assumptions discussed above, while holding all other assumptions constant:

Effect of Changing Critical Actuarial Assumptions

(In millions)		Pension Benefits		Health and Life Benefits	
Actuarial Assumptions	Percentage-Point Change in Assumption	Increase (Decrease) in Obligation	Increase (Decrease) in Cost	Increase (Decrease) in Obligation	Increase (Decrease) in Cost
Expected long-term return on plan assets	+/– 1.00 pt.	n/a	$(6.1) / $6.1	n/a	$(2.0) / $2.0
Discount rate	+/– 0.25	$(19.1) / $20.1	$(1.4) / $1.5	$(16.7) / $17.4	$(1.7) / $1.8
Rate of compensation increase	+/– 0.25	$4.8 / $(4.7)	$0.9 / $(0.8)	n/a	n/a
Healthcare cost trend rate	+/– 1.00	n/a	n/a	$74.7 / $(61.2)	$10.9 / $(9.4)

Differences between actuarial assumptions and actual plan results are deferred and amortized into cost when the accumulated differences exceed ten percent of the greater of the Projected Benefit Obligation or the market-related value of the plan assets. If necessary, the excess is amortized over the average remaining service period of active employees.

In addition to the assumptions listed above, the measurement of the Plans' obligations and costs are dependent on other factors such as employee demographics, the level of contributions made to the Plans, earnings on the Plans' assets and mortality rates. Effective September 30, 2006, Washington Gas updated the mortality table it uses to develop its mortality rates to reflect more current life expectancy experience. This change did not have a significant effect on the obligations of the Plans.

Refer to Note 12 of the Notes to Consolidated Financial Statements for a listing of the actuarial assumptions used and for a further discussion of the accounting for the Plans.

OTHER ACCOUNTING MATTERS

Accounting for Stock-Based Compensation

Effective October 1, 2005, we adopted SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123(R)), which replaces SFAS No. 123, and supersedes Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* and SFAS No. 148, *Accounting for Stock-Based Compensation-Transition and Disclosure.* Under SFAS No. 123(R), we measure and record compensation expense for both our stock option and performance share awards based on their fair value at the date of grant. Prior to October 1, 2005, we had accounted for our share-based awards in accordance with SFAS No. 123, as amended, which permitted us to apply APB Opinion No. 25 and related interpretations in accounting for our stock-based compensation plans. In accordance with APB Opinion No. 25, we did not record in our financial statements compensation expense related to our stock option grants. We did record compensation expense over the requisite service period related to our performance shares awarded based on the market value of WGL Holdings' common stock at the end of each reporting period.

As permitted by SFAS No. 123(R), we used the modified prospective method of adopting the new accounting standard; accordingly, financial results for fiscal years 2005 and 2004 have not been retroactively adjusted to reflect the effects of SFAS No. 123(R). In accordance with SFAS No. 123(R), we recognized total stock-based compensation expense of $4.4 million for the fiscal year ended September 30, 2006, along with related income tax benefits of $1.8 million. For fiscal years 2005 and 2004, we recognized total stock-based compensation expense of $3.4 million and $1.9 million, respectively, along with related income tax benefits of $1.2 million and $660,000, respectively, in accordance with APB Opinion No. 25.

To value our stock options under SFAS No. 123(R), we continue to use the Black-Scholes model that was previously used for disclosure purposes under SFAS No. 123, as amended. We use a Monte Carlo simulation model to value our performance shares under SFAS No. 123(R), as they contain market conditions based on total shareholder return compared to a peer group.

As of September 30, 2006, there was $4.1 million of total unrecognized compensation expense related to our share-based awards. This cost is expected to be recognized over a weighted average period of 1.6 years, which comprises 1.7 years and 1.5 years for performance shares and stock options, respectively. Refer to Notes 1 and 13 of the Notes to Consolidated Financial Statements for a further discussion of our share-based awards.

Discontinued Operations

During the quarter ended June 30, 2006, we completed a plan for the disposition of ACI, a wholly owned subsidiary of Washington Gas Resources. On September 29, 2006, we sold all of the outstanding shares of common stock of ACI to an unrelated party. ACI was previously reported as part of our commercial HVAC business segment. ACI has been reported as a discontinued operation of WGL Holdings and, accordingly, ACI's operating results, financial position and cash flows have been presented separately from our continuing operations in the consolidated financial statements of WGL Holdings for all fiscal years presented. Refer to the section entitled "*Results of Operations—Summary Results*" for a further discussion of this sale.

WGL HOLDINGS, INC.

RESULTS OF OPERATIONS

Summary Results

WGL Holdings reported net income of $87.6 million, or $1.79 per share, for the fiscal year ended September 30, 2006, as compared to net income of $103.5 million, or $2.11 per share, and $96.6 million, or $1.98 per share, for the fiscal years ended September 30, 2005 and 2004, respectively. We earned a return on average common equity of 9.6 percent, 11.8 percent and 11.6 percent, respectively, during each of these three fiscal years.

Net income for fiscal year 2006 included an after-tax loss of $7.1 million, or $0.15 per share, from the discontinued operations of ACI. This was comprised of a net loss from ACI's operations of $3.5 million, or $0.07 per share, and an after-tax loss of $3.6 million, or $0.08 per share, that resulted from the September 29, 2006 sale of ACI. Net income for fiscal years 2005 and 2004 included a net loss from ACI's discontinued operations of $2.6 million, or $0.05 per share, and $3.0 million, or $0.06 per share, respectively.

We reported consolidated income from continuing operations of $94.7 million, or $1.94 per share, for the fiscal year ended September 30, 2006, as compared to income from continuing operations of $106.1 million, or $2.16 per share, and $99.6 million, or $2.04 per share, reported for fiscal years 2005 and 2004, respectively. The following is a discussion of year-over-year trends related to our results from continuing operations.

Fiscal Year 2006 vs. Fiscal Year 2005. Income from continuing operations for fiscal year 2006, when compared to fiscal year 2005, primarily reflects lower net income from both our retail energy-marketing and regulated utility segments. Earnings comparisons attributable to our retail energy-marketing business reflect lower gross margins from the sale of natural gas, partially offset by improved gross margins from electric sales. The year-over-year decline in earnings of our regulated utility segment was primarily attributable to lower consumption of natural gas by customers due to customer conservation, coupled with higher operating expenses, interest costs and income taxes. Favorably affecting fiscal year 2006 earnings for the regulated utility segment were continued customer growth, increased revenues related to recoverable carrying costs on storage gas inventory balances, and favorable adjustments related to cost of gas and customer billings.

Income from continuing operations for fiscal year 2006 compared to fiscal year 2005 also reflects the following transactions related to our regulated utility and non-utility business segments. Fiscal year 2006 included: *(i)* a charge of $4.6 million (pre-tax) recorded by our regulated utility segment related to a proposed regulatory order and *(ii)* a $3.1 million (pre-tax) reversal by our energy-marketing segment of fees that were previously assessed by a regulatory body and accrued in prior fiscal years. Fiscal year 2005 included: *(i)* a favorable tax adjustment of $2.5 million related to the regulated utility segment and *(ii)* a charge of $912,000 that resulted principally from the resolution of a legal contingency allocated to the remaining portion of our commercial HVAC business.

Fiscal Year 2005 vs. Fiscal Year 2004. The $6.5 million, or $0.12 per share, improvement in income from continuing operations for fiscal year 2005, when compared to fiscal year 2004, primarily reflects higher earnings from our retail energy-marketing business, driven primarily by increased gross margins from natural gas sales. This improvement was partially offset by lower earnings from our regulated utility segment that were attributable to lower natural gas deliveries to firm customers and higher operating expenses. Customer growth, coupled with lower interest costs and income taxes, favorably affected fiscal year 2005 earnings for our regulated utility segment.

As discussed above, fiscal year 2005 also included the $2.5 million favorable tax adjustment related to our regulated utility segment, and the $912,000 charge related to our commercial HVAC business segment. Fiscal year 2004 included the following transactions: *(i)* the recognition of additional depreciation expense unrelated to fiscal year 2004 of $3.5 million (pre-tax) that was recorded in connection with a Virginia rate order; *(ii)* an after-tax gain of $5.8 million from the sale of two buildings in which we held a carried interest (Maritime sale) and *(iii)* a charge of $870,000 for the impairment of goodwill related to the remaining portion of our commercial HVAC business.

The following table summarizes our net income (loss) by operating segment for fiscal years ended September 30, 2006, 2005 and 2004.

Net Income (Loss) by Operating Segment

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
Regulated utility	**$84,599**	$ 87,492	$88,951
Non-utility operations:			
Retail energy-marketing	**13,315**	22,294	8,280
Commercial HVAC	**450**	(1,314)	(2,438)
Total major non-utility	**13,765**	20,980	5,842
Other, principally non-utility activities	**(3,670)**	(2,400)	4,802
Total non-utility	**10,095**	18,580	10,644
Income from continuing operations	**94,694**	106,072	99,595
Loss from discontinued operations, net of income tax benefit	**(7,116)**	(2,579)	(2,958)
Net income	**$87,578**	$103,493	$96,637

Regulated Utility Operating Results

The following table summarizes the regulated utility segment's operating results for fiscal years ended September 30, 2006, 2005 and 2004.

Regulated Utility Operating Results

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
Operating revenues	**$1,637,491**	$1,402,905	$1,293,675
Operating expenses:			
Cost of gas	**1,031,650**	796,413	694,639
Operation and maintenance	**236,467**	241,582	231,001
Depreciation and amortization	**92,712**	89,859	91,510
General taxes and other assessments			
Revenue taxes	**55,964**	58,170	50,079
Other	**40,726**	40,478	36,544
Total operating expenses	**1,457,519**	1,226,502	1,103,773
Operating income	**179,972**	176,403	189,902
Interest expense	**44,026**	41,600	43,141
Other (income) expenses-net, including preferred stock dividends	**(630)**	161	(917)
Income tax expense	**51,977**	47,150	58,727
Net income	**$ 84,599**	$ 87,492	$ 88,951

Fiscal Year 2006 vs. Fiscal Year 2005. The regulated utility segment reported net income of $84.6 million, or $1.73 per share, for the fiscal year ended September 30, 2006, as compared to net income of $87.5 million, or $1.79 per share, for fiscal year 2005. The year-over-year decrease in earnings primarily reflects a decline in total natural gas deliveries to firm customers due to customer conservation. Natural gas deliveries to firm customers fell 70.5 million therms, or 5.5 percent, in fiscal year 2006 from 2005. In addition to customer conservation, natural gas deliveries declined from the effect of warmer weather in fiscal year 2006. Weather, as measured by heating degree days (HDDs) was 2.5 percent warmer than normal in fiscal year 2006, as compared to 5.9 percent colder than normal in fiscal year 2005. Unlike customer conservation, the earnings effect of warmer-than-normal weather experienced in fiscal year 2006 was neutralized by the application of the RNA mechanism in Maryland and other weather protection strategies implemented in Virginia and the District of Columbia, as discussed below.

Favorably affecting earnings for fiscal year 2006 when compared to the prior fiscal year were: *(i)* the addition of 19,811 active customer meters since the end of the prior fiscal year; *(ii)* $7.3 million (pre-tax) of increased revenues from recoverable carrying costs on a higher average balance of storage gas inventory that was the result of both higher natural gas prices and volumes; *(iii)* favorable adjustments related to the annual reconciliation of lost-and-unaccounted-for gas and *(iv)* favorable adjustments related to the recovery of natural gas costs.

Our weather protection products, coupled with the timing of HDDs during fiscal year 2006, resulted in weather having a favorable effect on net income for fiscal year 2006 in relation to normal weather. For fiscal year 2006, net income was enhanced in relation to normal weather by an estimated $2.5 million (after-tax), or $0.05 per share, despite the 2.5 percent warmer-than-normal weather during this period. This benefit resulted primarily from the colder-than-normal weather experienced during the first quarter of fiscal year 2006. For the fiscal year ended September 30, 2005, the 5.9 percent colder-than-normal weather during that year contributed an estimated $5 million (after-tax), or $0.10 per share, to net income.

Prior to October 1, 2005, we managed weather risk for all jurisdictions of Washington Gas with a weather insurance policy designed to protect against 50 percent of the effects of warmer-than-normal weather. That policy expired on September 30, 2005. Commencing in fiscal year 2006, our weather management strategy varied by jurisdiction: *(i)* in Maryland, we implemented the RNA mechanism on October 1, 2005 upon approval by the PSC of MD (refer to Note 15 of the Notes to Consolidated Financial Statements); *(ii)* in the District of Columbia, we purchased a new weather insurance policy that became effective on October 1, 2005 and *(iii)* in Virginia, we purchased a weather derivative that became effective on December 18, 2005 and expired on May 31, 2006 (refer to the section entitled *"Market Risk—Weather Risk"*).

In Maryland, the RNA mechanism is designed to stabilize the level of revenues collected from customers by eliminating the effect of deviations in normal customer usage caused by weather and other factors, such as customer conservation. Periods of colder-than-normal weather generally would cause Washington Gas to reduce its revenues and establish a refund liability to customers, while the opposite would generally result during periods of warmer-than-normal weather. Accordingly, the warmer-than-normal weather during fiscal year 2006 resulted in an increase in revenues and the recording of a receivable from customers to reflect Washington Gas' protection from warmer-than-normal weather and factors other than weather, such as customer conservation, that are covered under the RNA mechanism.

In the District of Columbia and Virginia, both the weather insurance and the weather derivative were designed to provide full protection from the negative financial effects of warmer-than-normal weather. Unlike the Maryland RNA, the weather insurance and derivative products enable us to retain the benefits from colder-than-normal weather. In fiscal year 2006, the regulated utility segment benefited $8.9 million (pre-tax) from these weather protection products in relation to the prior fiscal year. These realized benefits are reflected in "Operation and maintenance" expenses which, for fiscal year 2006, include a benefit of $4.7 million (pre-tax) from the new weather insurance and derivative products, net of the related premium costs of these products. This compares to $4.2 million (pre-tax) of expense included in "Operation and maintenance" expenses for fiscal year 2005 to reflect the premium cost associated with the expired insurance policy.

Earnings of the regulated utility segment for fiscal year 2006 reflect a $3.8 million (pre-tax) increase in operation and maintenance expenses, after excluding the $8.9 million (pre-tax) enhancement to earnings from the weather protection products, as discussed above. Principally contributing to the increased expenses was $1.8 million of increased expenses associated with information technology projects, and $1.6 million of higher expenses for uncollectible accounts. Results from the regulated utility segment also reflect higher depreciation and amortization expense and increased interest expense that, together, reduced pre-tax income by $5.3 million. Further discussion of operation and maintenance and depreciation and amortization expenses of

Washington Gas is included under Management's Discussion for Washington Gas. Also refer to the section of this Management's Discussion entitled *"Interest Expense"* for a further discussion of this cost.

Fiscal year ended September 30, 2006 also included a charge of $4.6 million (pre-tax) recorded to "Cost of gas" related to a proposed order by a Hearing Examiner of the PSC of MD that recommends the disallowance of certain natural gas costs incurred by Washington Gas and billed to Maryland customers from September 2003 through August 2004. The Hearing Examiner recommended the disallowance of these costs in connection with its annual review of Washington Gas' natural gas costs. We have appealed the proposed order before the PSC of MD, asserting that the recommendation is without merit (refer to Note 15 of the Notes to Consolidated Financial Statements). On a comparative basis, the regulated utility segment benefited in fiscal year 2005 from a favorable income tax adjustment of $2.5 million related to a change in estimate.

Fiscal Year 2005 vs. Fiscal Year 2004. The regulated utility segment reported net income of $87.5 million, or $1.79 per share, for fiscal year 2005 as compared to net income of $89.0 million, or $1.82 per share, for fiscal year 2004. This comparison primarily reflects a decrease of 28.7 million therms, or 2.2 percent, in total natural gas deliveries to firm customers during fiscal year 2005 due, in part, to warmer weather experienced primarily during the second quarter of fiscal year 2005, the most significant period of Washington Gas' winter heating season. However, during other periods within fiscal year 2005, Washington Gas experienced lower than expected natural gas deliveries because the increase in HDDs did not correlate highly with the change in the volume of natural gas delivered during those periods. For the fiscal year ended September 30, 2005, weather was 5.9 percent colder than normal, enhancing net income in relation to normal weather by an estimated $5 million (after-tax), or $0.10 per share. For fiscal year 2004, weather was 6.1 percent colder than normal, and was estimated to have improved net income by approximately $10 million (after-tax), or $0.20 per share.

Favorably affecting earnings for the regulated utility segment for fiscal year 2005 was the addition of 22,043 active customer meters, the effect of changes in rates charged to customers that were implemented in Maryland on November 6, 2003 and in the District of Columbia on November 24, 2003, as well as $2.1 million (pre-tax) of increased earnings from carrying costs on a higher average balance of storage gas inventory. Earnings for fiscal year 2005, when compared to fiscal year 2004, also reflect $10.6 million (pre-tax) of increased operation and maintenance expenses, partially offset by $1.7 million (pre-tax) of lower depreciation and amortization expense, and $1.5 million (pre-tax) of lower interest expense (refer to the section of this Management's Discussion entitled *"Interest Expense"*). The regulated utility segment also benefited from reduced income tax expense due to a combination of lower pre-tax income and a lower effective income tax rate which, in part, reflects a favorable tax adjustment of $2.5 million recorded in fiscal year 2005.

Further discussion of the operating results of Washington Gas is included in the Management's Discussion for Washington Gas.

Non-Utility Operating Results

Our continuing non-utility operations are comprised of two business segments: *(i)* retail energy-marketing and *(ii)* the remaining portion of commercial HVAC after excluding the effects of discontinued operations. Certain of our transactions are not significant enough to report as stand-alone business segments, and therefore are aggregated as "Other Activities" which are included as part of non-utility operations for purposes of segment reporting (refer to Note 17 of the Notes to Consolidated Financial Statements).

Total net income from our continuing non-utility operations for fiscal year 2006 was $10.1 million, or $0.21 per share, a decrease of $8.5 million, or $0.16 per share, from fiscal year 2005. The year-over-year decline in these earnings primarily reflects lower earnings of our retail energy-marketing segment.

Continuing non-utility operations reported total net income of $18.6 million, or $0.37 per share, for the fiscal year ended September 30, 2005, an increase of $8.0 million, or $0.15 per share, over fiscal year 2004. The year-over-year increase in net income was driven by improved earnings from our retail energy-marketing segment. On a comparative basis, fiscal year 2004 included an after-tax gain of $5.8 million from the Maritime sale.

The following table depicts the composition of the changes in revenues for the non-utility business segments.

Composition of Non-Utility Revenues and Other Statistics

	Years Ended September 30,		
	2006	2005	2004
Non-Utility Operating Revenues *(In thousands)*			
Retail energy-marketing	**$1,001,596**	$ 773,046	$ 789,859
Commercial HVAC	**13,138**	9,482	6,963
Other	**639**	1,425	1,673
Total non-utility operating revenues	**$1,015,373**	$ 783,953	$ 798,495
Retail Energy-Marketing Statistics			
Natural gas			
Therm sales *(thousands of therms)*	**696,694**	713,676	716,577
Number of customers *(end of period)*	**142,700**	144,800	150,800
Electricity			
Electricity sales *(thousands of kWhs)*	**2,412,407**	2,680,469	6,658,926
Number of accounts *(end of period)*	**63,300**	36,200	44,500

Retail Energy-Marketing

Our retail energy-marketing subsidiary, WGEServices, was established in 1997, and sells natural gas and electricity on an unregulated, competitive basis directly to residential, commercial and industrial customers.

Fiscal Year 2006 vs. Fiscal Year 2005. The retail energy-marketing segment reported net income of $13.3 million, or $0.27 per share, for the fiscal year ended September 30, 2006, as compared to net income of $22.3 million, or $0.45 per share, reported for the prior fiscal year. The $9.0 million, or $0.18 per share, decline in earnings for this business primarily reflects lower gross margins (revenues less costs of energy) from the sale of natural gas primarily due to: *(i)* unfavorable changes in the valuation of derivative contracts; *(ii)* the unfavorable year-over-year comparison resulting from $2.0 million (after-tax) of reduced expenses recorded in fiscal year 2005 related to the termination of two natural gas supply contracts; *(iii)* the unfavorable year-over-year comparison from the recording in fiscal year 2005 of $1.2 million (after-tax) of gross margin adjustments related to certain contracts and *(iv)* a 2.4 percent decrease in the volume of natural gas sold. Favorably affecting earnings in fiscal year 2006 were increased gross margins from the sale of electricity, and the reversal of expenses in fiscal year 2006 of $3.1 million (pre-tax) related to certain fees assessed by the PSC of DC that were accrued in prior fiscal years.

Lower gross margins from natural gas sales were affected, in part, by net mark-to-market losses in fiscal year 2006, as compared to net mark-to-market gains recognized in fiscal year 2005. Market valuation losses or gains are recorded principally in connection with derivative contracts that are used to mitigate the risk of volatility in the market price of natural gas during the winter heating season. The year-over-year net change in the valuation of these instruments decreased net income by $6.1 million (after-tax) for the fiscal year ended September 30, 2006. Refer to *"Market Risk—Price Risk Related to the Retail Energy-Marketing Segment"* for a further discussion of these derivative transactions.

The decrease in gross margins from natural gas sales in fiscal year 2006 also was attributable to the inclusion in fiscal year 2005 of $2.0 million (after-tax) of reduced expenses related to the termination of contracts with two suppliers for the forward purchase of natural gas. These fixed-price contracts were terminated due to the suppliers' inability to fulfill contractual obligations during the 2005-2006 winter heating season due to the natural gas supply shortage in the Gulf of Mexico region. In consideration of the contract termination, the suppliers paid a fee to WGEServices, recorded as a reduction to "Non-utility cost of energy-related sales" in fiscal year 2005, for an amount equivalent to the excess of the market price over the fixed price that WGEServices incurred in fiscal year 2006 to replace the contractual shortfall. The higher cost of the replacement gas was reflected in fiscal year 2006 when delivered.

Gross margins from electric sales increased significantly during fiscal year 2006, reflecting a dramatic rise in the gross margin per kilowatt hour sold, partially offset by a 10 percent decline in electric sales volumes. Electric customers grew 75 percent in fiscal year 2006 when compared to the end of the prior fiscal year. This customer growth was principally the result of new competitive opportunities that emerged near the end of the third quarter of fiscal year 2006 due to sharp increases in competing rates offered by electric utilities in Maryland and Delaware.

Favorably affecting the operating results of the energy-marketing segment for fiscal year 2006 was the reversal of certain administrative fees that were previously assessed by the PSC of DC. WGEServices, which recorded these assessments as an expense in prior fiscal years, protested its payment of these fees. During fiscal year 2006, WGEServices received a favorable court decision from its appeal regarding the payment of these fees in which the court decided that the energy-marketing business is entitled to a refund. Accordingly, the energy-marketing segment benefited $3.1 million (pre-tax) from its reversal in fiscal year 2006 of fees accrued as an expense in prior fiscal years.

Fiscal Year 2005 vs. Fiscal Year 2004. Net income for the retail energy-marketing segment was $22.3 million, or $0.45 per share, for fiscal year 2005, an increase over net income of $8.3 million, or $0.17 per share, reported for fiscal year 2004. The $14.0 million, or $0.28 per share, improvement was attributable to *(i)* $2.0 million (after-tax) of reduced expenses in fiscal year 2005 related to the termination of the two natural gas supply contracts; *(ii)* favorable changes in the valuation of derivative contracts which increased net income by $1.8 million (after-tax) and *(iii)* $1.2 million (after-tax) of favorable gross margin adjustments recorded in fiscal year 2005 related to certain contracts. The remainder of the year-over-year improvement in earnings for this segment for fiscal year 2005 was attributable to reduced expenses associated with uncollectible accounts, partially offset by lower gross margins from electric sales as the 59.7 percent decline in electric sales volumes more than offset the increase in the gross margin per kilowatt hour sold.

Commercial HVAC

As a result of the discontinued operations of ACI, WGESystems comprises the remaining portion of the commercial HVAC segment. WGESystems offers large-scale HVAC installations and related services to commercial and government customers.

The commercial HVAC segment reported net income of $450,000, or $0.01 per share, for fiscal year 2006, an improvement of $1.8 million, or $0.04 per share, over the net loss of $1.3 million, or $0.03 per share, reported for fiscal year 2005. Operating results for fiscal year 2005 represented an improvement of $1.1 million, or $0.02 per share, over the net loss of $2.4 million, or $0.05 per share, reported for fiscal year 2004. The improvements in both fiscal years 2006 and 2005 were attributable to higher operating income that was driven by increased sales and lower selling, general and administrative expenses. The comparison between fiscal year 2006 and 2005 also was affected by a charge of $912,000, or $0.02 per share, recorded in fiscal year 2005 that resulted principally from the resolution of a legal contingency related to our investment in the HVAC business.

Other Non-Utility Activities

As previously discussed, certain of our transactions are not significant enough on a stand-alone basis to warrant treatment as a business segment. For purposes of segment reporting, these transactions are aggregated as "Other Activities" and included as part of non-utility operations (see Note 17 of the Notes to Consolidated Financial Statements).

Results for our other non-utility activities for fiscal year 2006 reflect a net loss of $3.7 million, or $0.07 per share, as compared to a net loss of $2.4 million, or $0.05 per share, reported for fiscal year 2005. The net loss in fiscal year 2005 from other non-utility activities represented a $7.2 million, or $0.15 per share, decrease from the net income of $4.8 million, or $0.10 per share, reported for fiscal year 2004. This decline was primarily due to an after-tax gain of $5.8 million, or $0.12 per share, realized in fiscal year 2004 from the Maritime sale.

Other Income (Expenses)—Net

Other income (expenses)—net was income of $3.2 million, $2.3 million and $9.1 million for fiscal years 2006, 2005 and 2004, respectively. The significant decrease in income in fiscal year 2005 when compared to 2004 was principally due to the after-tax gain of $5.8 million realized in fiscal year 2004 from the Maritime sale.

Interest Expense

Interest expense was $48.3 million for the fiscal year ended September 30, 2006, an increase of $5.0 million over fiscal year 2005. Fiscal year 2005 interest expense was $43.3 million, a decrease of $830,000 from the $44.1 million level for fiscal year 2004. Long-term debt primarily comprises unsecured MTNs issued solely by Washington Gas. The weighted average cost of MTNs was 6.15 percent, 6.27 percent and 6.46 percent at September 30, 2006, 2005 and 2004, respectively. The following table shows the components of the changes in interest expense between years.

Composition of Interest Expense Changes

	Increase/(Decrease)	
(In millions)	**2006 vs 2005**	2005 vs 2004
Long-term debt	**$(0.4)**	$(0.8)
Short-term debt	**4.1**	0.5
Other (includes AFUDC*)	**1.3**	(0.5)
Total	**$ 5.0**	$(0.8)

* *Represents Allowance for Funds Used During Construction.*

The $5.0 million increase in WGL Holdings' interest expense for fiscal year 2006 compared to fiscal year 2005 primarily reflects higher interest costs associated with short-term borrowings due to an increase of over 200 basis points in the weighted average cost of these borrowings, coupled with a higher average balance of short-term debt outstanding. Approximately two-thirds of the increase in short-term interest expense resulted from the higher short-term debt requirements of the non-utility operations. The year-over-year increase also reflects higher other interest expense primarily related to customer deposits and other miscellaneous items. Partially offsetting the increase in short-term and other interest expense were reduced interest costs on long-term debt due to a decrease in the embedded cost of these borrowings as a result of refinancing previously outstanding amounts, partially offset by a higher average balance of long-term debt outstanding.

The $830,000 decrease in WGL Holdings' interest expense for fiscal year 2005 compared to fiscal year 2004 reflects reduced interest costs on long-term debt due to a decrease in the average balance of long-term debt outstanding. Interest expense on short-term debt rose, reflecting an increase of approximately 130 basis points in the weighted average cost of short-term debt, partially offset by a lower average balance of short-term debt outstanding. Fiscal year 2005 also reflects lower other interest expense due to an $882,000 loss recorded in fiscal year 2004 related to an interest-rate swap, partially offset by interest associated with other miscellaneous items.

LIQUIDITY AND CAPITAL RESOURCES

General Factors Affecting Liquidity

It is important for us to have access to short-term debt markets to maintain satisfactory liquidity to operate our businesses on a near-term basis. Acquisition of natural gas, electricity, pipeline capacity, and the need to finance accounts receivable and storage gas inventory are our most significant short-term financing requirements. The need for long-term capital is driven primarily by capital expenditures and maturities of long-term debt.

Significant swings can take place in the level of short-term debt we require due primarily to changes in the price and volume of natural gas and electricity purchased to satisfy customer demand, and also due to seasonal cash collections on accounts receivable. Back-up financing to our commercial paper programs in the form of revolving credit agreements enables us to maintain access to short-term debt markets. Our ability to obtain such financing depends on our credit ratings, which are greatly affected by our financial performance. Also potentially affecting access to short-term debt capital is the liquidity of financial markets, as well as the nature of any restrictions that might be placed upon us, such as ratings triggers or a requirement to provide creditors with additional credit support in the event of a determination of insufficient creditworthiness.

The ability to procure sufficient levels of long-term capital at reasonable costs is determined by the level of our capital expenditure requirements, our financial performance and the effect of these factors on our credit ratings and investment alternatives available to investors.

We have a capital structure goal to maintain our common equity ratio in the mid-50 percent range of total consolidated capital. The level of this ratio varies during the fiscal year due to the seasonal nature of our business. This seasonality is also evident in the variability of our short-term debt balances, which are typically higher in the fall and winter months, and substantially lower in the spring when a significant portion of our current assets is converted into cash at the end of the winter heating season. Accomplishing this capital structure objective and maintaining sufficient cash flow are necessary to maintain attractive credit ratings for WGL Holdings and Washington Gas, and to allow access to capital at reasonable costs. As of September 30, 2006, total consolidated capitalization, including current maturities of long-term debt and excluding notes payable, comprised 58.1 percent common equity, 1.8 percent preferred stock and 40.1 percent long-term debt. Our cash flow requirements and our ability to provide satisfactory resources to satisfy those requirements are primarily influenced by the activities of Washington Gas and, to a lesser extent, the non-utility operations.

We believe we have sufficient liquidity to satisfy our financial obligations. At September 30, 2006, we did not have any restrictions on our cash balances that would affect the payment of common or preferred stock dividends by WGL Holdings or Washington Gas.

Short-Term Cash Requirements and Related Financing

Washington Gas' business is weather sensitive and seasonal, causing short-term cash requirements to vary significantly during the year. Over 75 percent of the total therms delivered in Washington Gas' service area (excluding deliveries to two electric generation facilities) occur during the first and second fiscal quarters. Accordingly, Washington Gas typically generates more net income in the first six months of the fiscal year than it does for the entire fiscal year. During the first six months of our fiscal year, Washington Gas generates large sales volumes, and its cash requirements peak when accounts receivable, unbilled revenues and storage gas inventories are at their highest levels. During the last six months of our fiscal year, after the winter heating season, Washington Gas will typically experience a seasonal net loss due to reduced demand for natural gas. During this period, many of Washington Gas' assets are converted into cash, which Washington Gas generally uses to reduce and sometimes eliminate short-term debt and to acquire storage gas for the next heating season.

Our retail energy-marketing subsidiary, WGEServices, has seasonal short-term cash requirements resulting from its need to purchase storage gas inventory in advance of the winter period in which the storage gas is sold. In addition, WGEServices must continually pay its suppliers of natural gas and electricity before it collects its accounts receivable balances resulting from these sales. WGEServices derives its funding to finance these activities from short-term debt issued by WGL Holdings.

Both Washington Gas and the retail energy-marketing segment maintain storage gas inventory. WGEServices maintains storage gas inventory that is assigned to it by natural gas utilities such as Washington Gas. Storage gas inventories represent gas purchased from producers and stored in facilities owned by third parties. Washington Gas and the retail energy-marketing segment generally pay for storage gas between heating seasons and withdraw it during the heating season. Significant variations in storage gas balances between years may occur, and are caused by the price paid to producers and marketers, which is a function of market fluctuations in the price of natural gas and changing requirements for storage volumes. For Washington Gas, such costs become a component of the cost of gas recovered from customers when volumes are withdrawn from storage. In addition, Washington Gas is able to specifically earn and recover its pre-tax cost of capital related to the varying level of the storage gas inventory balance it carries in each of the three jurisdictions in which it operates. For WGEServices, the cost of storage gas inventory is a component of its expected gas cost considered in making competitive contract offers to its customers.

Variations in the timing of collections of gas costs under Washington Gas' gas cost recovery mechanisms and the level of refunds from pipeline companies that will be returned to customers can significantly affect short-term cash requirements. Washington Gas had a $2.5 million and a $4.4 million net over-collection of gas costs at September 30, 2006 and 2005, respectively. The over-collection in both fiscal years stemmed primarily from an excess of gas costs recovered from customers over gas costs paid to suppliers. Generally, Washington Gas includes the amounts under-collected and over-collected in the captions "Gas costs and other regulatory assets" and "Gas costs and other regulatory liabilities," respectively, in its balance sheets as current assets and current liabilities. Amounts under- or over-collected that are generated during the current business cycle are reflected as a regulatory asset or liability until September 1 of each year, at which time the accumulated amount is transferred to gas costs due from/to customers as

appropriate. Most of the current balance will be returned to, or collected from, customers in fiscal year 2007. At September 30, 2006 and 2005, refunds received from pipelines and to be returned to Washington Gas' customers were not material.

WGL Holdings and Washington Gas utilize short-term debt in the form of commercial paper or unsecured short-term bank loans to fund seasonal requirements. Our policy is to maintain back-up bank credit facilities in an amount equal to or greater than our expected maximum commercial paper position. As of September 30, 2006, WGL Holdings and Washington Gas each have revolving credit agreements with a group of commercial banks that expire on September 30, 2010. The credit facility for WGL Holdings permits it to borrow up to $275 million, and further permits us to request prior to September 30, 2009, and the banks to approve, an additional line of credit of $50 million above the original credit limit, for a maximum potential total of $325 million. The credit facility for Washington Gas permits it to borrow up to $225 million, and further permits Washington Gas to request prior to September 30, 2009, and the banks to approve, an additional line of credit of $100 million above the original credit limit, for a maximum potential total of $325 million. There were no outstanding borrowings under these credit facilities at September 30, 2006 or 2005.

At September 30, 2006 and 2005, WGL Holdings and its subsidiaries had outstanding notes payable in the form of commercial paper, of $177.4 million and $40.9 million, respectively. Of the outstanding notes payable balance at September 30, 2006, $104.6 million and $72.8 million was commercial paper issued by WGL Holdings and Washington Gas, respectively. Of the outstanding notes payable balance at September 30, 2005, $30.5 million and $10.4 million was commercial paper issued by WGL Holdings and Washington Gas, respectively.

As a result of market concerns about the sufficiency of the supply of natural gas and other factors during the winter of 2005-2006, the price of the natural gas commodity paid by our customers rose sharply from levels experienced during the 2004-2005 winter heating season. During fiscal year 2006, higher gas costs increased customers' bills dramatically. Higher natural gas prices increased the difficulty of customers to pay their bills in a timely manner. Higher gas costs were a major cause of the need for WGL Holdings and Washington Gas to finance a higher level of accounts receivable than in prior years. Higher natural gas prices, combined with greater volumes, also increased our storage gas inventory balance. During the fiscal year ended September 30, 2006, we incurred higher short-term debt levels and greater short-term debt costs to finance the increased receivables and storage gas inventory caused by these circumstances. We also have incurred a higher level of uncollectible accounts expenses. The relationship between gas costs and short-term debt costs is likely to continue in the future.

Long-Term Cash Requirements and Related Financing

Our long-term cash requirements primarily depend upon the level of capital expenditures, long-term debt maturities and decisions to refinance long-term debt. Historically, we have devoted the majority of our capital expenditures to adding new Washington Gas customers in its existing service area. However, as a result of recent operating issues in Prince George's County, Maryland, that are described later in Management's Discussion, we forecast a greater level of replacement capital expenditures through fiscal year 2008 (refer to the section entitled *"Capital Expenditures"*).

At September 30, 2006, Washington Gas had the capacity, under a shelf registration that was declared effective by the SEC on June 8, 2006, to issue up to $300.0 million of MTNs. On June 14, 2006, Washington Gas executed a Distribution Agreement with certain financial institutions for the issuance and sale of debt securities covered by the shelf registration statement.

On June 23, 2006, the Maryland General Assembly enacted legislation which addresses electric industry restructuring issues in Maryland and other issues for all public utilities. Effective July 1, 2007, the legislation requires that all public utilities operating in Maryland, including Washington Gas, obtain approval from the PSC of MD before issuing stock, bonds, securities, notes, or other debt with a maturity greater than 12 months. We plan to request from the PSC of MD all necessary approvals relating to financing authorizations in order to maintain continuing access to financial markets.

Fiscal Year 2006 Activity. On January 18, 2006, Washington Gas issued $25.0 million of 5.17 percent MTNs due January 18, 2016, and $25.0 million of 5.70 percent MTNs due January 18, 2036. In conjunction with the issuance of the 5.17 percent MTNs, Washington Gas received $182,000 associated with the settlement of a forward-starting swap that had a notional principal amount of $25.0 million. Similarly, in conjunction with the issuance of the 5.70 percent MTNs, Washington Gas received $104,000 associated with the settlement of a forward-starting swap that had a notional principal amount of $25.0 million (refer to the section entitled *"Market Risk—Interest-Rate Risk"*). The effective cost of the newly-issued debt, after considering the amount received related to the two forward-starting swaps and amortization of discounts related to the debt issuances, is 5.16 percent

for the MTNs due 2016 and 5.72 percent for the MTNs due 2036. On February 15, 2006, Washington Gas used the combined cash proceeds from these debt issuances to retire $50.0 million of 6.15 percent MTNs through its exercise of call options.

On March 22, 2006, Washington Gas issued $25.0 million of 5.78 percent MTNs due March 15, 2036. In conjunction with this issuance, Washington Gas received $303,000 associated with the settlement of a forward-starting swap that had a notional principal amount of $25.0 million (refer to the section entitled *"Market Risk—Interest-Rate Risk"*). Additionally, on March 22, 2006, Washington Gas paid $26.0 million, plus accrued interest, to retire $25.0 million of 7.31 percent MTNs that were due on October 30, 2007, by exercising a make-whole call feature that required Washington Gas to pay to the debt holder a call premium of $958,000 for redeeming the debt prior to its stated maturity date. This premium was recorded as a regulatory asset, and is being amortized in accordance with regulatory accounting requirements. The effective cost of the newly-issued debt, after considering the amount received related to the forward-starting swap, the amount paid related to the make-whole call premium and discounts related to the debt issuance, is 6.03 percent.

Fiscal Year 2005 Activity. During the fiscal year ended September 30, 2005, Washington Gas retired a total of $60.5 million of MTNs. On March 7, 2005, Washington Gas, through exercise of a call option, retired $20.0 million of MTNs. The MTNs redeemed were $10.0 million of 7.76 percent MTNs and $10.0 million of 7.75 percent MTNs that had a nominal maturity date in March 2025. On June 9, 2005, Washington Gas, through exercise of a call option, retired $20.0 million of 6.50 percent MTNs that had a nominal maturity date in June 2025. Additionally, on June 20, 2005, Washington Gas retired $20.5 million of 7.45 percent MTNs that matured on the same date. Washington Gas paid the applicable accrued interest on each debt retirement date.

In August 2005, Washington Gas replaced the retired debt, as discussed above, with $60.5 million of newly issued MTNs. On August 9, 2005, Washington Gas issued $20.0 million of 4.83 percent MTNs due August 2015 to replace the MTNs retired on March 7, 2005. On August 11, 2005, Washington Gas issued $40.5 million of 5.44 percent MTNs due August 2025 to replace the MTNs retired in June 2005. Concurrent with the issuance of the $20.0 million of 4.83 percent MTNs, Washington Gas paid $364,000 associated with the settlement of a forward-starting swap that had a notional principal amount of $20.0 million. Similarly, concurrent with the issuance of the $40.5 million of 5.44 percent MTNs, Washington Gas paid $2.2 million associated with the settlement of a forward-starting swap that had a notional principal amount of $40.5 million (refer to the section entitled *"Market Risk—Interest-Rate Risk"*). The effective cost of the newly-issued debt, after considering the amount paid related to the two forward-starting swaps, is 5.15 percent and 5.98 percent for the $20.0 million and $40.5 million debt issuances, respectively.

Security Ratings

The table below reflects the current credit ratings for the outstanding debt instruments of WGL Holdings and Washington Gas. Changes in credit ratings may affect WGL Holdings' and Washington Gas' cost of short-term and long-term debt and their access to the capital markets. Credit ratings can change at any time.

Credit Ratings for Outstanding Debt Instruments

	WGL Holdings		Washington Gas	
Rating Service	Unsecured Medium-Term Notes (Indicative)[(a)]	Commercial Paper	Unsecured Medium-Term Notes	Commercial Paper
Fitch Ratings	A+	F1	AA-	F1+
Moody's Investors Service	Not Rated	Not Prime	A2	P-1
Standard & Poor's Ratings Services[(b)]	AA−	A-1	AA−	A-1

(a) *Indicates the ratings that may be applicable if WGL Holdings were to issue unsecured MTNs.*
(b) *This agency has held a negative outlook on the long-term debt ratings of WGL Holdings and Washington Gas since July 2, 2004.*

Ratings Triggers and Certain Debt Covenants

WGL Holdings and Washington Gas pay facility fees on their credit facilities based on the long-term debt ratings of Washington Gas. In the event the long-term debt of Washington Gas is downgraded below certain levels, WGL Holdings and Washington Gas would be required to pay higher facility fees. There are five different levels of fees. The credit facility for WGL Holdings defines its

applicable fee level as one level below the level applicable to Washington Gas. Under the terms of the credit facilities, the lowest level facility fee is six basis points and the highest is ten basis points.

Under the terms of the credit facilities, the ratio of consolidated indebtedness to consolidated total capitalization can not exceed 0.65 to 1.0 (65.0 percent). In addition, WGL Holdings and Washington Gas are required to inform lenders of changes in corporate existence, financial conditions, litigation and environmental warranties that might have a material adverse effect. The failure to inform the lenders' agent of changes in these areas deemed material in nature might constitute default under the agreement. A default, if not remedied, may lead to a suspension of further loans and/or acceleration in which obligations become immediately due and payable. At September 30, 2006, we were in compliance with all of the covenants under our revolving credit facilities.

For certain of Washington Gas' natural gas purchase and pipeline capacity agreements, if the long-term debt of Washington Gas is downgraded to or below the lower of a BBB rating by Standard & Poor's Ratings Services or a Baa2 rating by Moody's Investors Service, or if Washington Gas is deemed by a counterparty not to be creditworthy, then the counterparty may withhold service or deliveries, or may require additional credit support.

WGL Holdings has guaranteed payments for certain purchases of natural gas and electricity on behalf of WGEServices (refer to *"Contractual Obligations, Off-balance Sheet Arrangements and Other Commercial Commitments"* for a further discussion of these guarantees). If WGL Holdings is assigned a credit rating below BBB- by Standard & Poor's Ratings Services or Baa3 by Moody's Investors Service, WGEServices would be required to provide additional credit support.

Cash Flows Provided by Operating Activities

The primary drivers for our operating cash flows are cash payments received from gas customers, offset by our payments for gas costs, operation and maintenance expenses, taxes and interest costs. Although long-term interest rates remain relatively low and we have been able to take advantage of refinancing certain of our long-term debt at lower interest rates, interest expense for fiscal year 2006 reflects the effect of a rise in short-term interest rates.

Net cash provided by operating activities totaled $85.7 million, $232.5 million and $237.7 million for fiscal years 2006, 2005 and 2004, respectively. Net cash provided by operating activities includes net income applicable to common stock, as adjusted for non-cash earnings and charges, as well as changes in working capital. Certain changes in working capital from September 30, 2005 to September 30, 2006 are described below.

- Accounts receivable and unbilled revenues increased $32.0 million from September 30, 2005, primarily reflecting an increase in receivables associated with both electric and natural gas sales of WGEServices. The increase in electricity receivables is due to a significant increase in both the number of customers and retail sales prices of electricity, while the increased natural gas receivables reflects higher retail natural gas sales prices.

- Storage gas inventory levels increased $43.1 million from September 30, 2005 due to higher natural gas prices and increased storage capacity to accommodate the requirements for the 2006-2007 winter heating season.

- Deferred purchased gas costs—net increased $23.6 million, representing a regulatory asset of $12.0 million at September 30, 2006 compared to a regulatory liability of $11.6 million at September 30, 2005. This increase is due primarily to fair value losses in 2006 associated with certain of Washington Gas' contracts for the purchase and sale of natural gas, as compared to fair value gains recognized in fiscal year 2005.

During fiscal years 2005 and 2004, storage gas inventory rose $35.3 million and $53.0 million, respectively, due to higher natural gas costs and increased storage capacity. Accounts payable and other accrued liabilities increased $20.8 million and $36.7 million during fiscal years 2005 and 2004, respectively, largely to fund higher natural gas and electricity purchases. During fiscal year 2005, customer deposits and advance payments increased $37.7 million from September 30, 2004 due to a revised credit policy requiring security deposits from new customers of Washington Gas, and the receipt of a security deposit held from an electricity supplier of WGEServices. The deposits at Washington Gas are reported as current liabilities, and may be refunded to the depositor-customer at various times throughout the year based on the customer's payment habits. At the same time, other customers make new deposits that enable the balance of customer deposits to remain relatively steady.

Cash Flows Provided by (Used in) Financing Activities

Cash flows provided by financing activities totaled $75.0 million for fiscal year 2006, and cash flows used in financing activities totaled $119.2 million and $132.6 million for fiscal years 2005 and 2004, respectively. During fiscal year 2006, we increased our notes payable by a net amount of $136.5 million due to increased working capital requirements. This increase in notes payable was partially offset by common stock dividend payments totaling $65.3 million. Additionally during fiscal year 2006, we refinanced $75.0 million of long-term debt with cash proceeds from the issuance of lower-cost, long-term debt (refer to the section entitled *"Long-Term Cash Requirements and Related Financing"*).

Cash flows used in financing activities during fiscal year 2005 reflect a $54.8 million net decrease in notes payable, coupled with common stock dividend payments totaling $64.0 million. Additionally during fiscal year 2005, we refinanced $60.5 million of long-term debt with proceeds from the issuance of lower-cost, long-term debt. During fiscal year 2004, cash flows used in financing activities reflect a $71.0 million net decrease in notes payable, coupled with common stock dividend payments totaling $62.7 million. Additionally during fiscal year 2004, we refinanced $36.0 million of long-term debt with proceeds from the issuance of $37.0 million of lower-cost, long-term debt.

The following table reflects the issuances and retirements of long-term debt that occurred during fiscal years 2006, 2005 and 2004 (also refer to Note 6 of the Notes to Consolidated Financial Statements).

Long-Term Debt Activity

	2006		2005		2004	
(In millions)	**Interest Rate**	**Amount**	Interest Rate	Amount	Interest Rate	Amount
Medium-term notes						
Issued	**5.17 – 5.78%**	**$ 75.0**	4.83 – 5.44%	$ 60.5	4.88%	$ 37.0
Retired	**6.15 – 7.31%**	**(75.0)**	6.50 – 7.76%	(60.5)	6.95%	(36.0)
Other financing						
Issued[(a)]	**4.76 – 5.61%**	**5.7**	8.00%	0.1	6.75%	0.8
Retired[(b)]	**5.61%**	**(2.7)**	5.99 – 8.00%	(16.5)	–	–
Other activity	**–**	**(0.1)**	–	(0.1)	–	(0.1)
Total		**$ 2.9**		$(16.5)		$ 1.7

(a) *Includes the non-cash issuance of a $3.0 million note used to finance capital expenditures for fiscal year 2006.*
(b) *Includes the non-cash extinguishment of project debt financing of $2.7 million and $16.4 million for fiscal years 2006 and 2005, respectively.*

Cash Flows Used in Investing Activities

Net cash flows used in investing activities totaled $161.2 million, $115.0 million and $102.9 million during fiscal years 2006, 2005 and 2004, respectively. In fiscal years 2006, 2005 and 2004, $156.4 million, $111.1 million and $107.9 million, respectively, of cash was utilized for capital expenditures made on behalf of Washington Gas. Additionally, fiscal year 2004 included cash proceeds of $6.4 million (pre-tax) received from the Maritime sale.

Capital Expenditures

The following table depicts our actual capital expenditures for fiscal years 2004, 2005 and 2006, and projected capital expenditures for fiscal years 2007 through 2011. Our capital expenditure program includes investments to extend service to new areas, and to ensure safe, reliable and improved service.

Capital Expenditures

	Actual			Projected					
(In millions)	2004	2005	**2006**	2007	2008	2009	2010	2011	Total
New business	$ 67.5	$ 58.2	**$ 48.7**	$ 54.8	$ 57.0	$ 56.9	$ 67.3	$ 61.6	$297.6
Replacements									
Rehabilitation project	–	8.2	**47.8**	47.2	40.8	–	–	–	88.0
Other	24.9	22.5	**22.7**	20.9	20.5	29.9	27.2	26.6	125.1
LNG storage facility	–	1.5	**5.8**	1.1	1.5	44.5	60.0	20.0	127.1
Other	20.9	33.7	**36.5**	34.5	39.0	33.2	22.1	20.1	148.9
Total–accrual basis[(a)]	113.3	124.1	**161.5**	158.5	158.8	164.5	176.6	128.3	786.7
Non-cash adjustments	(4.9)	(11.3)	**(1.7)**	–	–	–	–	–	–
Total–cash basis	$108.4	$112.8	**$159.8**	$158.5	$158.8	$164.5	$176.6	$128.3	$786.7

[(a)] *Excludes Allowance for Funds Used During Construction. Includes capital expenditures accrued and capital expenditure adjustments recorded in the fiscal year.*

The 2007 to 2011 projected periods include $297.6 million for continued growth to serve new customers, and $213.1 million primarily related to the replacement and betterment of existing capacity. In connection with a rehabilitation project in Prince George's County, Maryland, a total of $56.0 million was expended in fiscal years 2005 and 2006, and up to $88.0 million is projected to be expended between fiscal years 2007 through 2008, representing a total of $144.0 million. As explained in the section entitled *"Contractual Obligations, Off-Balance Sheet Arrangements and Other Commercial Commitments—Operating Issues in Prince George's County, Maryland,"* the amount that will be expended on this rehabilitation project could be reduced depending upon the outcome of procedures and testing being performed on facilities in a portion of Prince George's County, Maryland.

Projected expenditures also reflect $148.9 million of other expenditures, which include general plant. Additionally, the projected period contains capital expenditures to construct a necessary, new source of peak day capacity within the boundaries of the natural gas distribution system to support customer growth and pressure requirements on the entire natural gas distribution system. Specifically, these estimated expenditures are expected to be used to construct a one billion cubic foot LNG storage facility on the land used for former storage facilities by Washington Gas in Chillum, Maryland. This new storage facility is currently estimated to cost a total of $148.6 million, of which $127.1 million is included in the Projected Capital Expenditures table as costs that are expected to be incurred between fiscal years 2007 through 2011. The constructed facility is currently expected to be completed and in service by the 2011-2012 winter heating season. This represents a delay from the originally planned completion date, which was expected by the 2008-2009 winter heating season, due to zoning and other legal challenges. On November 8, 2006, the District Council of Prince George's County issued a final decision denying Washington Gas' application related to its proposed construction of the LNG peaking plant. The District Council held that current zoning restrictions prohibit such construction. Washington Gas appealed this decision to the Prince George's County Circuit Court on November 22, 2006. Until such time when these legal challenges are resolved and the LNG plant is built, Washington Gas has planned for alternative sources of supply to meet its customers' peak day requirements. These planned alternatives include the acquisition of additional interstate pipeline capacity, in combination with investments by Washington Gas to upgrade the infrastructure of its transmission and distribution system. Capital expenditures related to the planned infrastructure improvements are expected to be completed by fiscal year 2011, and are reflected in the above table for the projected periods shown. This plan is expected to provide for sufficient sources of natural gas to meet our customers' peak day demand requirements until the new LNG storage facility is constructed and in service.

CONTRACTUAL OBLIGATIONS, OFF-BALANCE SHEET ARRANGEMENTS AND OTHER COMMERCIAL COMMITMENTS

Contractual Obligations

WGL Holdings and Washington Gas have certain contractual obligations that extend beyond fiscal year 2006. These commitments include long-term debt, lease obligations and unconditional purchase obligations for pipeline capacity, transportation and storage services, and certain natural gas and electricity commodity commitments. The estimated obligations as of September 30, 2006 for future fiscal years are shown below.

Estimated Contractual Obligations and Commercial Commitments

		Years Ended September 30,					
(In millions)	**Total**	2007	2008	2009	2010	2011	Thereafter
Pipeline and storage contracts[(a)]	**$1,415.1**	$ 141.5	$146.5	$129.9	$123.1	$110.1	$ 764.0
Medium-term notes[(b)]	**634.1**	60.0	20.1	75.0	32.5	30.0	416.5
Other long-term debt[(b)]	**3.2**	1.0	1.1	1.1	–	–	–
Interest expense[(c)]	**394.2**	37.9	35.0	31.7	28.0	25.1	236.5
Gas purchase commitments–Washington Gas[(d)]	**652.0**	336.3	92.3	89.8	87.5	46.1	–
Gas purchase commitments–WGEServices[(e)]	**756.4**	540.3	160.7	46.5	8.9	–	–
Electric purchase commitments[(f)]	**289.9**	206.0	59.7	14.6	6.9	2.7	–
Operating leases	**42.7**	4.6	4.5	4.2	3.0	3.0	23.4
Other long-term commitments[(g)]	**29.6**	12.7	8.5	4.4	1.5	1.4	1.1
Total	**$4,217.2**	$1,340.3	$528.4	$397.2	$291.4	$218.4	$1,441.5

(a) *Represents minimum payments under natural gas transportation, storage and peaking contracts which have expiration dates through fiscal year 2028. These contracts were entered into based on current estimates of growth of the Washington Gas system, together with current expectations of the timing and extent of unbundling initiatives in the Washington Gas service territory. Additionally, includes minimum payments for WGEServices pipeline contracts.*

(b) *Represents scheduled repayment of principal including the assumed exercise of a put option by the debt holders of $60.0 million in 2007 and $8.5 million in 2010.*

(c) *Represents the scheduled interest payments associated with MTNs and other long-term debt.*

(d) *Includes short-term gas purchase commitments to purchase fixed volumes of natural gas under Washington Gas' regulatory-approved hedging program, as well as long-term gas purchase commitments that contain fixed volume purchase requirements. Commitment amounts are estimated based on both forecasted market prices and fixed premiums for minimum purchases under these purchase commitments.*

(e) *Represents commitments based on a combination of market prices at September 30, 2006 and fixed price contract commitments for natural gas delivered to various city gate stations, including the cost of transportation to that point, which is bundled in the purchase price.*

(f) *Represents electric purchase commitments which are based on existing fixed price and fixed volume contracts.*

(g) *Includes certain Information Technology service contracts. Also includes committed payments related to certain environmental response costs.*

The table above reflects fixed and variable obligations. Certain of these estimates reflect likely purchases under various contracts, and may differ from minimum future contractual commitments disclosed in Note 15 of the Notes to Consolidated Financial Statements.

When a customer selects an unregulated third-party marketer to provide natural gas supply, Washington Gas generally assigns pipeline and storage capacity to unregulated third-party marketers to deliver natural gas to Washington Gas' city gate. In order to provide the gas commodity to customers who do not select an unregulated third-party marketer, Washington Gas has a commodity acquisition plan to acquire the natural gas supply to serve the customer. In connection with this energy acquisition plan, Washington Gas utilizes an Asset Manager to acquire a portion of the necessary supply to serve these customers. Washington Gas' commitment to the Asset Manager, when implementing its option to purchase gas supply through April 30, 2007, is at a market price that is tied to various public indices for natural gas. The contract commitment is related to customer demand, there are no minimum bill commitments, and no amount is included in the table above for these contracts.

For commitments related to Washington Gas' pension and post-retirement benefit plans, during fiscal year 2007, Washington Gas does not expect to make any contributions to its qualified, trusteed, non-contributory defined benefit pension plan covering all active and vested former employees of Washington Gas. On August 17, 2006, the Pension Protection Act of 2006 (the Act) was

signed into law. The Act, among other things, sets new funding requirements and new deduction limits for defined benefit pension plans. The new requirements will be phased in over time. The impact of this new legislation will be determined in the future based on how certain provisions are implemented through regulations and guidelines.

We expect to make payments totaling $1.3 million in fiscal year 2007 on behalf of participants in our non-funded Supplemental Executive Retirement Plan. We also expect to contribute $32.7 million to our health and life insurance benefit plans on behalf of retirees during fiscal year 2007. For a further discussion of our pension and post-retirement benefit plans, refer to Note 12 of the Notes to Consolidated Financial Statements.

Financial Guarantees

WGL Holdings has guaranteed payments primarily for certain purchases of natural gas and electricity on behalf of the retail energy-marketing segment. At September 30, 2006, these guarantees totaled $327.8 million. Termination of these guarantees is coincident with the satisfaction of all obligations of WGEServices covered by the guarantees. WGL Holdings also issued guarantees totaling $4.0 million at September 30, 2006 that were made on behalf of certain of our non-utility subsidiaries associated with their banking transactions. For all of its financial guarantees, WGL Holdings may cancel any or all future obligations imposed by the guarantees upon written notice to the counterparty, but WGL Holdings would continue to be responsible for the obligations that had been created under the guarantees prior to the effective date of the cancellation.

Operating Issues in Prince George's County, Maryland

On April 1, 2005, Washington Gas announced that it would address a significant increase in the number of natural gas leaks on its distribution system in a portion of Prince George's County, Maryland. Washington Gas retained an engineering consulting firm to determine the reason for the increase in leaks in the affected area of Prince George's County. Based on the work conducted to date by the consulting firm, there are several contributing factors to the higher leak rates of seals on couplings. However, in our opinion, the relevant factor that explains the higher incidence of leaks in the affected area of Prince George's County is the change in the composition of gas resulting from a change in the gas supply arising from the reactivation of the Dominion Cove Point LNG terminal.

Given the increase in the number of natural gas leaks experienced in the affected area of Prince George's County, Maryland in fiscal year 2005, Washington Gas announced in that year that it would replace gas service lines and rehabilitate gas mains that contain the applicable mechanical couplings in the affected area of the distribution system in Prince George's County (rehabilitation project) with a projected date of completion by the end of December 2007. The original estimate of the cost of the rehabilitation project is $144 million. This cost estimate could differ materially from the actual costs incurred for the work associated with this project. Our planned capital expenditures for fiscal years 2007 through 2008 reflect the current cost estimate of the rehabilitation project.

Refer to the section entitled *"Operating Issues in Prince George's County, Maryland"* under Item 1 of this report for a further discussion of this matter. Also refer to the section entitled *"Liquidity and Capital Resources—Capital Expenditures"* for a further discussion of the estimated costs associated with this project.

CREDIT RISK

Regulated Utility Segment

Certain suppliers that sell natural gas to Washington Gas have either relatively low credit ratings or are not rated by major credit rating agencies. In the event of a supplier's failure to deliver contracted volumes of gas, Washington Gas may need to replace those volumes at prevailing market prices, which may be higher than the original transaction prices, and pass these costs through to its sales customers under the purchased gas cost adjustment mechanisms (refer to the section entitled *"Market Risk—Price Risk Related to the Regulated Utility Segment"*). To manage this supplier credit risk, Washington Gas screens suppliers' creditworthiness and asks suppliers as necessary for financial assurances including, but not limited to, letters of credit and parental guarantees. During times of rising natural gas prices, Washington Gas has requested and received increased levels of financial assurance from its suppliers.

Washington Gas is also exposed to the risk of non-payment of utility bills by certain of its customers. To manage this customer credit risk, Washington Gas may require cash deposits from its high risk customers to cover payment of their bills. The deposits are held for varying periods of time, typically a minimum of one year and, as defined by regulatory tariffs, may be refunded if the customer makes satisfactory payments to Washington Gas during the holding period of the customer deposit. There are no

restrictions on Washington Gas' use of these customer deposits. Washington Gas pays interest to its customers on these deposits in accordance with the requirements of its regulatory commissions.

Retail Energy-Marketing Segment

Certain suppliers that sell natural gas or electricity to WGEServices have either relatively low credit ratings or are not rated by major credit rating agencies. Depending on the ability of these suppliers to deliver natural gas or electricity under existing contracts, WGEServices could be financially exposed for the difference between the price at which WGEServices has contracted to buy these commodities, and the replacement cost of these commodities that may need to be purchased. WGEServices has a wholesale supplier credit policy in place that is designed to mitigate wholesale credit risks through a requirement for credit enhancements. In accordance with this policy, WGEServices has obtained credit enhancements from certain of its suppliers. WGEServices continuously monitors the unsecured credit limits it will accept from certain suppliers or their guarantors.

MARKET RISK

We are exposed to various forms of market risk including commodity price risk, weather risk and interest-rate risk. The following discussion describes these risks and our management of them.

Price Risk Related to the Regulated Utility Segment

Washington Gas actively manages its gas supply portfolio to balance its sales and delivery obligations. Washington Gas includes the cost of the natural gas commodity and pipeline services in the purchased gas costs that it includes in firm customers' rates, as permitted by its jurisdictional tariffs and subject to regulatory review.

In order to mitigate commodity price risk for its firm customers, Washington Gas has specific regulatory approval in the District of Columbia, Maryland and Virginia to hedge transactions for a limited portion of its natural gas purchases. Three types of hedge instruments were approved for Washington Gas' use: *(i)* forward gas purchases at a fixed price; *(ii)* purchases of call options that effectively cap the cost of gas and *(iii)* a combination of call options purchased and put options sold that limits natural gas price exposure within a narrow band. While the regulatory approval for Virginia is permanent, the regulatory approvals in the District of Columbia and Maryland are pursuant to pilot programs, and Washington Gas is seeking to continue these programs. Certain of these contracts, as well as other contracts Washington Gas has entered into for the purchase or sale of natural gas, are required to be recorded at fair value (refer to Note 7 of the Notes to Consolidated Financial Statements for a discussion of the accounting for these derivative instruments). Such contracts had a net fair value loss of $490,000 at September 30, 2006, and a net fair value gain of $18.2 million at September 30, 2005. Of the September 30, 2006 net fair value loss, $14.4 million represented a fair value loss that was recorded on the balance sheet as a payable, with a corresponding $14.0 million recorded as a regulatory asset and $381,000 recorded to expense during fiscal year 2006. This was partially offset by a $13.9 million fair value gain that was recorded as a receivable, with a corresponding $11.6 million recorded as a regulatory liability and $2.3 million recorded to income during fiscal year 2006. Of the September 30, 2005 net fair value gain, $19.9 million represented a fair value gain that was recorded on the balance sheet as a receivable, with a corresponding amount recorded as a regulatory liability. This was partially offset by a $1.7 million fair value loss that was recorded on the balance sheet as a payable, with a corresponding amount recorded as a regulatory asset. This accounting is in accordance with regulatory accounting requirements for recoverable or refundable costs.

Washington Gas also mitigates price risk by injecting natural gas into storage during the summer months when prices are generally lower and less volatile, and withdraws that gas during the winter heating season when prices are generally higher and more volatile. Pursuant to a pilot program, Washington Gas has specific regulatory approval in Maryland and Virginia to hedge the cost of natural gas purchased for storage injection.

Price Risk Related to the Retail Energy-Marketing Segment

Our retail energy-marketing subsidiary, WGEServices, sells natural gas and electricity to retail customers at both fixed and indexed prices. We must manage daily and seasonal demand fluctuations for these products. The volume and price risks are evaluated and measured separately for natural gas and electricity.

WGEServices is exposed to market risk to the extent it does not closely match the timing and volume of natural gas and electricity it purchases with the related fixed price or indexed sales commitments. WGEServices' risk management policies and procedures are designed to minimize these risks.

Natural Gas. WGEServices faces risk in that over 50 percent of its annual natural gas sales volumes are subject to some variations in customer demand associated with fluctuations in weather and customer conservation. Purchases of natural gas to fulfill retail sales commitments are made generally under fixed-volume contracts that are based on normal weather assumptions. If there is a significant deviation from normal weather that causes purchase commitments to differ significantly from sales levels, WGEServices may be required to buy incremental natural gas or sell excess natural gas at prices that negatively impact gross margins. WGEServices manages this volumetric risk by using storage gas inventory and peaking services offered to marketers by the regulated utilities that provide delivery service for WGEServices' customers. WGEServices may also manage price risk through the use of derivative instruments, including financial options contracts and wholesale supply contracts that provide for volumetric variability. WGEServices also uses derivative instruments to minimize the price volatility from retail sales contracts which provide customers flexibility on both the price and volumes of natural gas being sold. At September 30, 2006, all of WGEServices' derivative instruments related to the purchase and sale of natural gas were recorded on our consolidated balance sheets at a net fair value gain of $386,000. This amount was comprised of a $3.3 million fair value gain that was recorded as a receivable, net of a $2.9 million fair value loss that was recorded as a payable. At September 30, 2005, our consolidated balance sheets reflected a fair value gain of $5.4 million related to these derivative instruments that was recorded as a receivable. In connection with these derivative instruments, WGEServices recorded a pre-tax loss of $4.5 million for the fiscal year ended September 30, 2006, and pre-tax gains of $3.8 million and $892,000 for the fiscal years ended September 30, 2005 and 2004, respectively.

Electricity. WGEServices procures electricity supply under contract structures in which WGEServices assumes the responsibility of matching its customer requirements with its supply purchases. WGEServices assembles the various components of supply, including electric energy, capacity, ancillary services and transmission service from multiple suppliers to match its customer requirements in accordance with its risk management policy.

To the extent WGEServices has not matched its customer requirements with its supply purchases, it could be exposed to electricity commodity price risk. WGEServices' electric business also is exposed to fluctuations in weather. Its purchases generally are made under fixed-volume contracts that are based on certain weather assumptions. If there are significant deviations in weather from these assumptions, WGEServices may incur price and volume variances that could negatively impact its expected gross margins.

For a small percentage of its electricity supply, WGEServices purchased full requirements services from wholesale electricity suppliers under master purchase and sale agreements, including electric energy, capacity and certain ancillary services, for resale to retail electric customers. On October 19, 2006, WGEServices terminated all remaining full requirements contracts and received a small termination settlement.

Value-At-Risk. WGEServices measures the market risk of its energy commodity portfolio by determining its value-at-risk. Value-at-risk is an estimate of the maximum loss that can be expected at some level of probability if a portfolio is held for a given time period. The value-at-risk calculation for natural gas and electric portfolios include assumptions for normal weather, new customers and renewing customers for which supply commitments have been secured. Based on a 95 percent confidence interval for a one-day holding period, WGEServices' value-at-risk at September 30, 2006 was approximately $569,000 and $579,000, related to its natural gas and electric portfolios, respectively.

Weather Risk

We are exposed to various forms of weather risk in both our regulated utility and unregulated business segments. For Washington Gas, a large portion of its revenues is volume driven and its current rates are based upon an assumption of normal weather. Without weather protection strategies, variations from normal weather will cause our earnings to increase or decrease, depending on the weather pattern. Prior to October 1, 2005, we managed weather risk for all jurisdictions of Washington Gas with a weather insurance policy that expired on September 30, 2005. As discussed below, Washington Gas obtained ratemaking provisions in Maryland that are designed to moderate the volatility of its revenues and customers' monthly bills due to variations in usage from factors such as weather and conservation. Washington Gas does not have similar ratemaking provisions in the District of Columbia or Virginia. Therefore, Washington Gas has relied on a weather insurance policy and a weather derivative, respectively, that are designed to provide full protection from the negative financial effects of warmer-than-normal weather in these jurisdictions, as discussed below. During the fiscal year ended September 30, 2006, Washington Gas recorded pre-tax benefits, net of premium costs, of $4.7 million

related to both its weather insurance in the District of Columbia and weather derivative in Virginia. This compares to $4.2 million of pre-tax premium expense recorded in both fiscal years ended September 30, 2005 and 2004 related to the expired weather insurance policy.

The financial results of our non-regulated energy-marketing business, WGEServices, are also affected by variations from normal weather in the winter relating to its natural gas sales, and in the summer relating to its electricity sales. WGEServices manages its weather risk related to its natural gas sales with, among other things, weather hedges, which are also discussed below in the section entitled *"HDD Derivatives."*

Billing Adjustment Mechanism. In August 2005, Washington Gas received approval from the PSC of MD to implement the RNA billing mechanism that is designed to stabilize the level of net revenues collected from Maryland customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels and other factors such as conservation. The RNA became effective on October 1, 2005. On September 15, 2006, Washington Gas filed an application with the SCC of VA requesting, among other things, to implement an RNA billing mechanism in Virginia. A final order by the SCC of VA on this and all other requests included in the application is pending. Refer to the section entitled *"Rates and Regulatory Matters"* under Item 1 of this report for a further discussion of these regulatory matters.

Weather Insurance. Prior to October 1, 2005, Washington Gas maintained a weather insurance policy covering all of its jurisdictions designed to cover 50 percent of the impact of warmer-than-normal weather on its financial results. The policy had a five-year term that expired on September 30, 2005. Effective October 1, 2005, Washington Gas purchased a new weather insurance policy designed to provide full protection from its exposure to warmer-than-normal weather in the District of Columbia. The new policy has a three-year term that expires on September 30, 2008.

The new policy covers Washington Gas' estimated net revenue exposure in the District of Columbia to variations in HDDs, subject to a maximum annual payment to Washington Gas of $6.6 million (pre-tax) and cumulative maximum payments of $13.1 million (pre-tax) over the three-year policy period. Pre-tax income is provided in the amount of $12,600 for each HDD warmer-than-normal during each fiscal year subject to the limitations previously described. Other than the cost of the insurance, Washington Gas pays nothing if weather is colder than normal. The policy's pre-tax average annual expense will be $1.9 million for fiscal years 2006 through 2008. This pre-tax expense is amortized based on the pattern of normal HDDs over the three-year policy period. No portion of the cost or benefit of this policy is considered in the regulatory process. Washington Gas recorded to income an accrued benefit, net of amortization expense of the related insurance premium, totaling $238,000 (pre-tax) for the fiscal year ended September 30, 2006 related to the new insurance policy in the District of Columbia. In October 2006, Washington Gas received a cash benefit of $1.3 million relating to this insurance policy.

HDD Derivatives. On December 8, 2005, Washington Gas purchased an HDD derivative designed to provide full protection from warmer-than-normal weather in Virginia, providing Washington Gas with $24,600 for every HDD below 2,833 during the period December 18, 2005 through May 31, 2006. This derivative expired on May 31, 2006. In June 2006, Washington Gas received a cash benefit of $6.2 million relating to this derivative. The pre-tax expense of this derivative of $1.7 million was amortized over the pattern of normal HDDs over the 5½-month term of the weather derivative. Washington Gas recorded to income a benefit, net of amortization expense of the related premium, totaling $4.4 million (pre-tax) related to the weather derivative for the fiscal year ended September 30, 2006.

On October 5, 2006, Washington Gas purchased a new HDD derivative designed to provide full protection from warmer-than-normal weather in Virginia during the upcoming 2006-2007 winter heating season. Washington Gas will receive $25,500 for every HDD below 3,735 during the period October 15, 2006 through April 30, 2007. The maximum amount that Washington Gas can receive under this arrangement is $9.4 million. The pre-tax expense of this derivative is $2.5 million, which is being amortized over the pattern of normal HDDs during the 6½-month term of the weather derivative.

WGEServices utilizes HDD derivatives for managing weather risks related to its natural gas sales, and also for its program that allows customers to pay a fixed amount for their gas requirements regardless of the amount of gas consumed. These hedges cover a portion of WGEServices' estimated net revenue exposure to variations in HDDs. For fiscal years 2006, 2005 and 2004, we recorded, including premium costs, pre-tax losses of $2.1 million, $246,000 and $114,000, respectively, related to these hedges.

Interest-Rate Risk

We are exposed to interest-rate risk associated with our debt financing costs. Management of this risk is discussed below.

Long-Term Debt. At September 30, 2006, we had fixed-rate MTNs and other long-term debt aggregating $576.3 million in principal amount, excluding current maturities and unamortized discounts, and having a fair value of $593.4 million. Fair value is defined as the present value of the debt securities' future cash flows discounted at interest rates that reflect market conditions as of September 30, 2006. While these are fixed-rate instruments and, therefore, do not expose us to the risk of earnings loss due to changes in market interest rates, they are subject to changes in fair value as market interest rates change. A total of $8.5 million, or approximately one percent, of Washington Gas' outstanding MTNs, excluding current maturities, have unexpired put options. In addition, a total of $421.5 million, or approximately 73 percent, of Washington Gas' outstanding MTNs, excluding current maturities, have make-whole call options, and no associated put options.

Using sensitivity analyses to measure this market risk exposure, we estimate that the fair value of our long-term debt would increase by approximately $25.8 million if interest rates were to decline by ten percent, or 61 basis points, from current market levels. We also estimate that the fair value of our long-term debt would decrease by approximately $23.8 million if interest rates were to increase by ten percent, or 61 basis points, from current market levels. In general, such an increase or decrease in fair value would impact earnings and cash flows only if Washington Gas were to reacquire all or a portion of these instruments in the open market prior to their maturity.

Derivative Instruments. Washington Gas utilizes derivative instruments from time to time in order to minimize its exposure to the risk of interest-rate volatility. As discussed below, during fiscal years 2006 and 2005, Washington Gas entered into forward-starting swaps that were intended to mitigate a substantial portion of the risk of rising interest rates associated with anticipated future debt issuances.

In February 2006, Washington Gas entered into a forward-starting swap with a notional principal amount of $25.0 million. Washington Gas terminated this forward-starting swap in conjunction with the issuance of $25.0 million of MTNs on March 22, 2006, and received $303,000 associated with the settlement of this hedge agreement.

In July 2005, Washington Gas entered into two forward-starting swaps with an aggregate notional principal amount of $50.0 million. At September 30, 2005, these swaps had a fair value gain totaling $106,000. Washington Gas terminated the two forward-starting swaps in conjunction with the issuance of $50.0 million of MTNs on January 18, 2006, and received a total of $286,000 associated with the settlement of these hedge agreements.

In September 2004, Washington Gas entered into two forward-starting swaps with an aggregate notional principal amount of $60.5 million. In August 2005, Washington Gas terminated the two forward-starting swaps concurrent with the August 2005 issuances of MTNs totaling $60.5 million. Washington Gas paid a total of $2.6 million associated with the settlement of these hedge agreements.

Refer to the section entitled *"Liquidity and Capital Resources—Long-Term Cash Requirements and Related Financing"* for a further discussion of the debt transactions related to these derivatives. Also refer to Note 7 of the Notes to Consolidated Financial Statements for a further discussion of the accounting for these derivatives transactions.

WASHINGTON GAS LIGHT COMPANY

This section of Management's Discussion focuses on the financial position and results of operations of Washington Gas for the reported periods. In many cases, explanations for the changes in financial position and results of operations for both WGL Holdings and Washington Gas are substantially the same.

RESULTS OF OPERATIONS

Summary Results

Washington Gas' net income applicable to its common stock was $84.5 million, $87.9 million and $95.3 million for the fiscal years ended September 30, 2006, 2005 and 2004, respectively. Net income for fiscal year 2006, when compared to fiscal year 2005, reflects higher expenses, including depreciation and amortization expense, interest expense and income taxes. Favorably affecting the earnings comparisons between fiscal years 2006 and 2005 were increased utility net revenues (utility revenues less the associated cost of gas and applicable revenue taxes). Net income for fiscal year 2005, when compared to fiscal year 2004, primarily reflects higher operation and maintenance expenses and increased general taxes and other assessments, partially mitigated by reduced depreciation and amortization expense and income taxes.

Utility Net Revenues

We analyze Washington Gas' financial performance based on its utility net revenues. As discussed below, Washington Gas includes the cost of the natural gas commodity and revenue taxes in its rates charged to customers. Both the cost of the natural gas commodity and revenue taxes are reflected in operating revenues. Accordingly, changes in the cost of natural gas and revenue taxes associated with sales made to customers have no direct effect on Washington Gas' utility net revenues or net income. The following table presents utility net revenues for fiscal years ended September 30, 2006, 2005 and 2004.

Utility Net Revenues

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
Operating revenues	**$1,637,491**	$1,402,905	$1,293,675
Less: Cost of gas	**1,031,650**	796,413	694,639
Revenue taxes	**55,964**	58,170	50,079
Utility net revenues	**$ 549,877**	$ 548,322	$ 548,957

Utility net revenues for Washington Gas were $549.9 million for fiscal year 2006, a slight improvement of $1.6 million over utility net revenues of $548.3 million for fiscal year 2005. Favorably contributing to the increase in utility net revenues was: *(i)* the addition of 19,811 active customer meters since the end of the prior fiscal year; *(ii)* increased revenues from recoverable carrying costs on a higher average balance of storage gas inventory; *(iii)* favorable adjustments related to Washington Gas' annual reconciliation of lost-and-unaccounted-for gas and *(iv)* favorable adjustments related to the recovery of natural gas costs. Substantially offsetting the improvements in utility net revenues was the effect of a decline in total natural gas deliveries to firm customers due to factors such as customer conservation, as well as warmer weather in fiscal year 2006 when compared to fiscal year 2005. The financial effects of warmer-than-normal weather experienced in fiscal year 2006 were neutralized by the application of the regulatory RNA mechanism in Maryland, as well as other weather protection strategies implemented in Virginia and the District of Columbia. The net benefits derived from the weather protection strategies in Virginia and the District of Columbia for fiscal year 2006 are reflected in "Operation and maintenance" expense as discussed below. Utility net revenues for fiscal year 2006 were also affected by a charge of $4.6 million (pre-tax) recorded to "Utility cost of gas" related to a proposed regulatory order to disallow certain natural gas costs incurred by Washington Gas and billed to Maryland customers.

Utility net revenues were $548.3 million for fiscal year 2005 compared to $549.0 million for fiscal year 2004. This comparison primarily reflects lower natural gas deliveries to firm customers, despite the fact that weather was relatively unchanged in fiscal year 2005 when compared to fiscal year 2004. Favorably contributing to utility net revenues for fiscal year 2005 was the addition of 22,043 active customer meters, coupled with the favorable effect of changes in rates charged to customers that were implemented in Maryland on November 6, 2003 and the District of Columbia on November 24, 2003.

Gas Deliveries, Weather and Meter Statistics

	Years Ended September 30,		
	2006	2005	2004
Gas Sales and Deliveries *(thousands of therms)*			
Firm			
Gas sold and delivered	**807,591**	847,838	856,135
Gas delivered for others	**403,812**	434,099	454,549
Total firm	**1,211,403**	1,281,937	1,310,684
Interruptible			
Gas sold and delivered	**6,185**	7,809	7,626
Gas delivered for others	**251,003**	279,924	268,483
Total interruptible	**257,188**	287,733	276,109
Electric generation—delivered for others	**108,315**	73,874	41,052
Total deliveries	**1,576,906**	1,643,544	1,627,845
Degree Days			
Actual	**3,710**	4,023	4,024
Normal	**3,807**	3,798	3,792
Percent colder (warmer) than normal	**(2.5)%**	5.9%	6.1%
Active customer meters (end of period)	**1,031,916**	1,012,105	990,062
New customer meters added	**24,693**	26,682	29,438

Gas Service to Firm Customers. The level of gas delivered to firm customers is highly sensitive to weather variability as a large portion of the natural gas delivered by Washington Gas is used for space heating. Washington Gas' rates are based on normal weather. The tariffs in the Maryland jurisdiction also include the effects of the RNA mechanism that was implemented in Maryland on October 1, 2005 upon approval by the PSC of MD (refer to the section entitled *"Jurisdictional Rates and Regulatory Matters—Maryland Jurisdiction"* included under Item 1 of this report). The tariffs for the remaining two jurisdictions in which Washington Gas operates do not have a weather normalization mechanism. Nonetheless, the combination of declining block rates in the Maryland and Virginia jurisdictions and the existence of a fixed demand charge in all jurisdictions to collect a portion of revenues reduce the effect that variations from normal weather have on utility net revenues.

During the fiscal year ended September 30, 2006, total gas deliveries to firm customers were 1.211 billion therms, a decrease of 70.5 million therms, or 5.5 percent, in deliveries from fiscal year 2005. The decline in natural gas deliveries to firm customers reflects lower natural gas consumption by customers due to customer conservation. The decline in natural gas deliveries also was attributable to warmer weather in fiscal year 2006 than in the prior fiscal year. In relation to normal weather patterns, weather for fiscal year 2006 was 2.5 percent warmer than normal, as compared to 5.9 percent colder than normal for fiscal year 2005. Although the warmer weather in fiscal year 2006 reduced total natural gas deliveries, the effect on net income of warmer-than-normal weather experienced in fiscal year 2006 was neutralized by the application of the RNA mechanism in Maryland, weather insurance in the District of Columbia and a weather derivative in Virginia. (Refer to the section entitled *"Weather Risk"* included in Management's Discussion for WGL Holdings for a further discussion of the weather protection strategies implemented in the District of Columbia and Virginia). Deliveries to Maryland customers represent approximately 40 percent of all therms delivered by Washington Gas.

During fiscal year 2005, firm therm deliveries decreased 28.7 million therms, or 2.2 percent, from fiscal year 2004 to 1.282 billion therms. The decrease in natural gas deliveries to firm customers occurred even though HDDs were relatively unchanged from fiscal year 2004. The decrease in natural gas deliveries was due, in part, to warmer weather experienced primarily during the second quarter of fiscal year 2005, the most significant period of Washington Gas' winter heating season. Washington Gas also experienced lower than expected natural gas deliveries during other periods within fiscal year 2005 that occurred because the increase in HDDs did not correlate highly with the change in the volume of gas delivered during those periods.

Many customers choose to buy the natural gas commodity from unregulated third-party marketers, rather than purchase the natural gas commodity and delivery service from Washington Gas on a "bundled" basis. Natural gas delivered to firm customers but purchased from unregulated third-party marketers represented 33.3 percent of total firm therms delivered during fiscal year 2006, compared to 33.9 percent and 34.7 percent delivered during fiscal years 2005 and 2004, respectively. On a per unit basis, Washington

Gas earns the same net revenues from delivering gas for others as it earns from bundled gas sales in which customers purchase both the natural gas commodity and the associated delivery service from Washington Gas. Therefore, Washington Gas does not experience any loss in utility net revenues when customers choose to purchase the natural gas commodity from an unregulated third-party marketer.

Gas Service to Interruptible Customers. Washington Gas must curtail or interrupt service to this class of customer when the demand by firm customers exceeds specified levels. Therm deliveries to interruptible customers decreased by 30.5 million therms, or 10.6 percent, in fiscal year 2006 compared to fiscal year 2005 primarily due to customers' use of alternative fuels as a result of higher natural gas prices. Therm deliveries to these customers increased by 11.6 million therms, or 4.2 percent, in fiscal year 2005 over fiscal year 2004, reflecting less curtailment of interruptible service due to warmer weather.

The effect on net income of any changes in delivered volumes and prices to interruptible customers is limited by margin-sharing arrangements that are included in Washington Gas' rate designs in the District of Columbia and, to a much smaller extent, in Virginia. In the District of Columbia, Washington Gas shares a majority of the margins earned on interruptible gas sales and deliveries with firm customers after a gross margin threshold is reached. A portion of the fixed costs for servicing interruptible customers is collected through the firm customers' rate design. In the Virginia jurisdiction, rates for customers using interruptible delivery service are based on a traditional cost of service approach, and Washington Gas retains all revenues from interruptible delivery service. Effective October 1, 2005, pursuant to implementing the Maryland RNA, rates for interruptible customers in Maryland are based on a traditional cost of service approach, and Washington Gas retains a defined amount above a pre-approved margin threshold level.

Gas Service for Electric Generation. Washington Gas sells and/or delivers natural gas for use at two electric generation facilities in Maryland that are each owned by companies independent of WGL Holdings. During fiscal year 2006, deliveries to these customers increased 46.6 percent over fiscal year 2005, and increased 80.0 percent in fiscal year 2005 over fiscal year 2004. These increases reflect the increased use by these customers of natural gas rather than alternative fuels. Washington Gas shares with firm customers a significant majority of the margins earned from natural gas deliveries to these customers. Therefore, changes in the volume of interruptible gas deliveries to these customers do not materially affect either net revenues or net income.

Cost of Gas

Washington Gas' cost of natural gas includes both fixed and variable components. Washington Gas pays fixed costs or "demand charges" to pipeline companies for system capacity needed to transport and store natural gas. Washington Gas pays variable costs, or the cost of the natural gas commodity itself, to natural gas producers. Variations in the utility's cost of gas expense result from changes in gas sales volumes, the price of the gas purchased and the level of gas costs collected through the operation of firm gas cost recovery mechanisms. Under these regulated recovery mechanisms, Washington Gas records cost of gas expense equal to the cost of gas recovered from customers and included in revenues. The difference between the firm gas costs paid and the gas costs recovered from customers is deferred on the balance sheet as an amount to be collected from or refunded to customers in future periods. Therefore, increases or decreases in the cost of gas associated with sales made to firm customers have no direct effect on Washington Gas' utility net revenues and net income. Changes in the cost of gas can cause significant variations in Washington Gas' cash provided by or used in operating activities. Washington Gas receives from or pays to its customers in the District of Columbia and Virginia, at short-term interest rates, carrying costs associated with under- or over-collected gas costs recovered from its customers.

The commodity costs of gas invoiced to Washington Gas (excluding the cost and related volumes applicable to sales made outside of the utility's service territory, referred to as off-system sales) were $1.10, $0.72 and $0.61 per therm for fiscal years 2006, 2005 and 2004, respectively. The higher gas costs in fiscal years 2006 and 2005 reflect increased price volatility in the wholesale market. This volatility intensified during the 2005-2006 winter heating season as a result of natural gas supply disruptions caused by hurricanes in the Gulf Coast region. Increased gas costs for fiscal year 2005 also reflect higher commodity gas prices associated with greater demand that resulted from colder-than-normal weather during that year. Increased gas costs generally will result in higher short-term debt levels and greater short-term interest costs to finance higher accounts receivables and storage gas inventory balances, as well as result in higher uncollectible accounts expenses.

Revenue Taxes

Revenue taxes, comprised principally of gross receipts taxes, decreased by $2.2 million in fiscal year 2006, and increased $8.1 million in fiscal year 2005. Changes in revenue taxes are impacted by changes in the volume of gas sold and delivered and the cost of the natural gas commodity. The decline in revenue taxes for fiscal year 2006 was attributable to a decline in volumes of gas sold and delivered, and to a change in the method of computation. In December 2005, the District of Columbia changed its method of tax

computation from a percent of revenue computation to a volume based computation. The increase in revenue taxes for fiscal year 2005 is principally due to an increase in tax rates charged to customers in Maryland. Washington Gas is allowed recovery of these amounts from its customers and, therefore, these increased fees do not affect total utility net revenues.

Utility Operating Expenses

Operation and Maintenance Expenses. Operation and maintenance expenses decreased $5.1 million, or 2.1 percent, from fiscal year 2005 to fiscal year 2006, and increased $11.3 million, or 4.9 percent, from fiscal year 2004 to fiscal year 2005.

The following table summarizes the major factors that contributed to the changes in operation and maintenance expenses.

Composition of Operation and Maintenance Expense Changes

	Increase/(Decrease)	
(In millions)	**2006 vs 2005**	2005 vs 2004
Weather insurance and derivative benefits—net	**$(8.9)**	$ –
Labor and incentive plans	**1.7**	4.2
Employee severance	**(0.1)**	(2.3)
Employee benefits	**(1.7)**	6.9
Uncollectible accounts	**1.6**	2.2
Information technology costs	**1.8**	1.2
Other non-labor operating expenses	**0.5**	(0.9)
Total	**$(5.1)**	$11.3

In fiscal year 2006, Washington Gas managed weather risk for the District of Columbia and Virginia with a weather insurance policy and weather derivative, respectively. Prior to fiscal year 2006, Washington Gas utilized a weather insurance policy, which expired on September 30, 2005, to manage weather risk for all three jurisdictions. Operation and maintenance expenses for fiscal year 2006, reflect a benefit of $4.7 million (pre-tax) from the proceeds of the new weather insurance and derivative products, net of premium costs, as compared to fiscal year 2005 which reflect a premium cost of $4.2 million (pre-tax) associated with the expired insurance policy. There was no change in the annual premium cost for fiscal year 2005 from fiscal year 2004.

Expenses related to labor and incentive plans increased $1.7 million in fiscal year 2006, and increased $4.2 million in fiscal year 2005. The increase in this expense for fiscal year 2006 relative to 2005 was due primarily to increased costs associated with equity-based compensation awards that were recorded pursuant to a new accounting standard that became effective on October 1, 2005 (refer to Note 1 of the Notes to Consolidated Financial Statements). The increase in these expenses in fiscal year 2005 relative to 2004 was due primarily to increased costs related to employee base pay and performance-based incentive awards, coupled with increased costs related to overtime incurred in connection with response to issues that arose in a portion of Washington Gas' distribution system in Prince George's County, Maryland such as special leak surveys, emergency response site visits and repairs. Fiscal year 2005 also benefited $2.3 million from reduced employee severance costs that were incurred in fiscal year 2004 related to operational efficiencies.

The $1.7 million decrease in employee benefits expenses in fiscal year 2006 when compared to 2005 was largely related to lower post-retirement benefit costs. The $6.9 million increase in these expenses in fiscal year 2005 when compared to 2004 largely reflects $10.0 million of increased post-retirement benefit costs, partially offset by a cost reduction of $3.1 million associated with a Medicare prescription drug subsidy (refer to Note 12 of the Notes to Consolidated Financial Statements).

The $1.6 million and $2.2 million increase in the provision for uncollectible accounts for fiscal years 2006 and 2005, respectively, were primarily attributable to increased revenues associated with higher natural gas prices. Operation and maintenance expenses for fiscal years 2006 and 2005 also reflect increased information technology costs of $1.8 million and $1.2 million, respectively, and other miscellaneous non-labor operating expenses.

Depreciation and Amortization. Depreciation and amortization expense for fiscal year 2006 was $92.0 million, an increase of $2.8 million, or 3.2 percent, over fiscal year 2005. The year-over-year increase is attributable, in part, to a reversal in fiscal year 2005 of $1.0 million of depreciation expense that was previously recorded in fiscal year 2004 related to the performance of an earnings test required by a December 18, 2003 Final Order of the SCC of VA (refer to Note 15 of the Notes to Consolidated Financial Statements). The remainder of the year-over-year increase reflects increased investment in property, plant and equipment.

Depreciation and amortization expense for fiscal year 2005 fell to $89.1 million, a decrease of $1.7 million, or 1.8 percent, from fiscal year 2004. The lower expense is attributable, in part, to the $1.0 million reversal of depreciation expense in fiscal year 2005 that was previously recorded in fiscal year 2004 related to the SCC of VA earnings test. The decline in this expense in fiscal year 2005, when compared to 2004, is also due to the inclusion in fiscal year 2004 of depreciation expense of $3.5 million (pre-tax) that was recorded in connection with the 2003 Virginia rate order. Washington Gas' composite depreciation and amortization rate was 3.44 percent for fiscal years 2006, and 3.48 for fiscal years 2005 and 2004.

General Taxes and Other Assessments. General taxes and other assessments decreased by $1.8 million in fiscal year 2006 compared to 2005, and increased by $12.2 million in fiscal year 2005 compared to 2004. General taxes and other assessments, as reported on Washington Gas' Statements of Income, include revenue taxes which decreased $2.2 million in fiscal year 2006 when compared to fiscal year 2005, and increased $8.1 million in fiscal year 2005 over 2004. As discussed above, we analyze revenue taxes as a component of utility net revenues. After considering the $8.1 million increase in revenue taxes for fiscal year 2005, the remaining $4.1 million increase in general taxes and other assessments for fiscal year 2005 was attributable to a sales and use tax that was newly assessed in Virginia, as well as increased real and personal property taxes in Maryland and other miscellaneous items.

Interest Expense

The explanations for changes in Washington Gas' interest expense are substantially the same as the explanations included in the Management's Discussion of WGL Holdings. Those explanations are incorporated by reference into this discussion.

Income Taxes

Income taxes increased $4.5 million in fiscal year 2006 when compared to 2005 primarily due to a combination of higher pre-tax income, coupled with a favorable tax adjustment of $2.5 million that benefited the prior fiscal year and thereby resulted in a comparably higher effective tax rate for fiscal year 2006. Income taxes decreased $6.2 million in fiscal year 2005 relative to 2004 primarily due to a combination of lower pre-tax income and a lower effective income tax rate. The lower effective income tax rate in fiscal year 2005 was primarily attributable to the $2.5 million favorable tax adjustment recorded in fiscal year 2005, coupled with increased non-taxable benefits associated with the Medicare prescription drug subsidy.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and capital resources for Washington Gas are substantially the same as the liquidity and capital resources discussion included in the Management's Discussion of WGL Holdings (except for certain items and transactions that pertain to WGL Holdings and its unregulated subsidiaries). Those explanations are incorporated by reference into this discussion.

REGULATORY MATTERS

The effects of regulatory decisions issued in fiscal years 2006 and 2005 have contributed favorably to Washington Gas' overall operating results. The operating results of Washington Gas reflect certain accounting adjustments necessitated by regulatory decisions.

Washington Gas determines its requests to modify existing rates based on the level of net investment in plant and equipment, operating expenses and the need to earn a just and reasonable return on invested capital. Over the last five years, Washington Gas has actively filed for rate relief in all of its jurisdictions to reflect the underlying cost of providing utility service. On September 15, 2006, Washington Gas filed an application with the SCC of VA to increase its annual utility net revenues in Virginia. This rate application is pending a Final Order by the SCC of VA (refer to *"Jurisdictional Rates and Regulatory Matters—Virginia Jurisdiction"* under Item 1 of this report). The following table summarizes major rate applications and results.

Summary of Major Rate Increase Applications and Results

Jurisdiction	Application Filed	Effective Date	Test Year 12 Months Ended	Increase in Annual Revenues (Millions)				Allowed Rate of Return	
				Requested		Granted		Overall	Equity
District of Columbia	02/07/03	11/24/03	09/30/02	$18.8	9.7%	$ 5.4[a]	2.8%	8.42%	10.60%
District of Columbia	06/19/01	04/09/03	12/31/00	16.3	6.8%	(5.4)	(2.2)%	8.83%	10.60%
District of Columbia	01/14/94	08/01/94	09/30/93	17.3	9.0%	6.4	3.4%	–[b]	–[b]
Maryland	03/31/03	11/06/03	12/31/02	27.2	6.8%	2.9	0.7%	8.61%	10.75%
Maryland	03/28/02	09/30/02	12/31/01	31.4	9.3%	9.3	2.8%	–[b]	–[b]
Maryland	06/01/94	12/01/94	03/31/94	17.6	5.7%	7.4	2.4%	9.79%[c]	11.50%[c]
Virginia	01/27/04	10/04/04	06/30/03	19.6	4.7%	–[e]	–[e]	8.44%	10.50%
Virginia	06/14/02	11/12/02[d]	12/31/01	23.8	6.6%	9.9	2.7%	8.44%	10.50%
Virginia	04/29/94	09/27/94	12/31/93	15.7	6.4%	6.8	2.7%	9.72%	11.50%

[a] *The revenue increase includes a reduction for the effect of a $6.5 million lower level of pension and other post-retirement benefit costs that had been previously deferred on the balance sheet of Washington Gas as a regulatory liability. This deferral mechanism ensures that the variation in these annual costs, when compared to the levels collected from customers, does not affect net income. Additionally, the $5.4 million annual revenue increase includes an $800,000 per year increase in certain expenses that are also subject to the regulatory deferral mechanism treatment. Accordingly, the total annual effect of the Final Order on Washington Gas' pre-tax income results in an annual increase of $11.1 million.*

[b] *Application was settled without stipulating the return on common equity.*

[c] *Rates were implemented as a result of a settlement agreement. The return on equity indicated in the Final Order of 11.50 percent was not utilized to establish rates.*

[d] *New depreciation rates effective January 1, 2002. New base rates went into effect subject to refund on November 12, 2002. Final Order released on December 18, 2003.*

[e] *Rate increases went into effect, subject to refund, on February 26, 2004 under an expedited rate application. On September 27, 2004, a Final Order was issued approving a proposed Stipulation filed by Washington Gas and other participants to resolve all issues related to this expedited rate case. Under the approved Stipulation, Washington Gas adjusted its billing rates commencing October 4, 2004 to reflect the level of annual revenues as determined in the previous Final Order issued on December 18, 2003 and noted in (d) above.*

Refer to the section entitled *"Rates and Regulatory Matters"* under Item 1 of this report and Note 15 of the Notes to Consolidated Financial Statements for a further discussion of Washington Gas' regulatory activities and related contingencies.

POTENTIAL BUSINESS OUTSOURCING

On July 11, 2006, we informed our employees that Washington Gas will evaluate proposals for possible business outsourcing portions of certain business functions. This evaluation follows our strategic objective of achieving improvements in the performance of Washington Gas' business and builds on our commitment to provide safe, reliable gas delivery service to our customers at a reasonable cost. The issuance of Requests for Proposals does not commit Washington Gas to outsource any functions, and follow-up action will be determined after completing a thorough evaluation of the proposals. However, if Washington Gas does ultimately outsource certain functions, it will do so with the intent of providing improved performance and reducing certain expenses. The timing and amount of any expense savings that may be realized and any costs that are incurred to achieve those savings, if outsourcing occurs, can not be determined at this time.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following issues related to our market risks are included under Item 7 of this report and are incorporated by reference into this discussion.

- Price Risk Related to the Regulated Utility Segment
- Price Risk Related to the Retail Energy-Marketing Segment
- Weather Risk
- Interest-Rate Risk

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

WGL Holdings, Inc.
Consolidated Statements of Income
Part II
Item 8. Financial Statements and Supplementary Data

(In thousands, except per share data)	Years Ended September 30, **2006**	2005	2004
OPERATING REVENUES			
Utility	**$1,622,510**	$1,379,390	$1,267,948
Non-utility	**1,015,373**	783,953	798,495
Total Operating Revenues	**2,637,883**	2,163,343	2,066,443
OPERATING EXPENSES			
Utility cost of gas	**1,016,669**	772,898	668,968
Non-utility cost of energy-related sales	**971,560**	713,522	751,272
Operation and maintenance	**258,022**	262,575	258,136
Depreciation and amortization	**93,055**	90,135	91,792
General taxes and other assessments	**96,187**	113,048	98,156
Total Operating Expenses	**2,435,493**	1,952,178	1,868,324
OPERATING INCOME	**202,390**	211,165	198,119
Other Income (Expenses)—Net	**3,241**	2,291	9,108
Interest Expense			
Interest on long-term debt	**40,634**	41,049	41,822
Other—net	**7,670**	2,254	2,311
Total Interest Expense	**48,304**	43,303	44,133
Dividends on Washington Gas preferred stock	**1,320**	1,320	1,320
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	**156,007**	168,833	161,774
INCOME TAXES	**61,313**	62,761	62,179
INCOME FROM CONTINUING OPERATIONS	**94,694**	106,072	99,595
Loss from discontinued operations, net of income tax benefit	**(7,116)**	(2,579)	(2,958)
NET INCOME (APPLICABLE TO COMMON STOCK)	**$ 87,578**	$ 103,493	$ 96,637
AVERAGE COMMON SHARES OUTSTANDING			
Basic	**48,773**	48,688	48,640
Diluted	**48,905**	49,008	48,847
EARNINGS PER AVERAGE COMMON SHARE			
Basic			
Income from continuing operations	**$ 1.94**	$ 2.18	$ 2.05
Loss from discontinued operations	**(0.14)**	(0.05)	(0.06)
Basic earnings per average common share	**$ 1.80**	$ 2.13	$ 1.99
Diluted			
Income from continuing operations	**$ 1.94**	$ 2.16	$ 2.04
Loss from discontinued operations	**(0.15)**	(0.05)	(0.06)
Diluted earnings per average common share	**$ 1.79**	$ 2.11	$ 1.98
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.3450**	$ 1.3225	$ 1.2950

The accompanying notes are an integral part of these statements.

WGL Holdings, Inc.
Consolidated Balance Sheets
Part II
Item 8. Financial Statements and Supplementary Data (continued)

	September 30,	
(In thousands)	**2006**	2005
ASSETS		
Property, Plant and Equipment		
At original cost	**$2,949,951**	$2,779,878
Accumulated depreciation and amortization	**(882,056)**	(810,862)
Net property, plant and equipment	**2,067,895**	1,969,016
Current Assets		
Cash and cash equivalents	**4,350**	4,842
Receivables		
Accounts receivable	**154,443**	135,980
Gas costs and other regulatory assets	**14,609**	9,711
Unbilled revenues	**46,557**	32,181
Allowance for doubtful accounts	**(17,676)**	(16,835)
Net receivables	**197,933**	161,037
Materials and supplies—principally at average cost	**18,302**	16,823
Storage gas—at cost (first-in, first-out)	**296,061**	252,925
Deferred income taxes	**11,360**	13,778
Other prepayments—principally taxes	**12,208**	10,677
Other	**21,808**	11,680
Current assets of discontinued operations	**–**	9,679
Total current assets	**562,022**	481,441
Deferred Charges and Other Assets		
Regulatory assets		
Gas costs	**11,950**	–
Other	**65,330**	64,236
Prepaid qualified pension benefits	**76,245**	75,965
Other	**7,964**	9,756
Other assets of discontinued operations	**–**	667
Total deferred charges and other assets	**161,489**	150,624
Total Assets	**$2,791,406**	$2,601,081
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shareholders' equity	**$ 921,807**	$ 893,992
Washington Gas Light Company preferred stock	**28,173**	28,173
Long-term debt	**576,139**	584,150
Total capitalization	**1,526,119**	1,506,315
Current Liabilities		
Current maturities of long-term debt	**60,994**	50,122
Notes payable	**177,376**	40,876
Accounts payable and other accrued liabilities	**208,501**	203,315
Wages payable	**13,761**	13,375
Accrued interest	**3,298**	2,919
Dividends declared	**16,826**	16,524
Customer deposits and advance payments	**49,595**	52,173
Gas costs and other regulatory liabilities	**14,212**	14,103
Accrued taxes	**8,963**	13,688
Other	**7,316**	1,622
Current liabilities of discontinued operations	**–**	3,210
Total current liabilities	**560,842**	411,927
Deferred Credits		
Unamortized investment tax credits	**13,151**	14,047
Deferred income taxes	**295,718**	292,273
Accrued pensions and benefits	**44,173**	41,011
Asset retirement obligations	**27,362**	–
Regulatory liabilities		
Accrued asset removal costs	**268,922**	272,124
Gas costs	**–**	11,600
Other	**17,235**	15,983
Other	**37,884**	35,402
Other liabilities of discontinued operations	**–**	399
Total deferred credits	**704,445**	682,839
Commitments and Contingencies (Note 15)		
Total Capitalization and Liabilities	**$2,791,406**	$2,601,081

The accompanying notes are an integral part of these statements.

WGL Holdings, Inc.
Consolidated Statements of Cash Flows
Part II
Item 8. Financial Statements and Supplementary Data (continued)

(In thousands)	Years Ended September 30, 2006	2005	2004
OPERATING ACTIVITIES			
Net income (applicable to common stock)	**$ 87,578**	$ 103,493	$ 96,637
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES			
Loss from discontinued operations, net of income tax benefit	**7,116**	2,579	2,958
Depreciation and amortization:			
Per Consolidated Statements of Income	**93,055**	90,135	91,792
Charged to other accounts	**3,788**	4,319	4,339
Deferred income taxes—net	**9,667**	7,674	28,387
Amortization of investment tax credits	**(896)**	(897)	(897)
Accrued/deferred pension cost	**(1,501)**	(4,988)	(5,213)
Earnings from sale of carried interest in real estate	**–**	–	(6,414)
Impairment of commercial HVAC goodwill	**–**	912	870
Other non-cash charges (credits)—net	**3,999**	3,149	1,769
CHANGES IN ASSETS AND LIABILITIES			
Accounts receivable and unbilled revenues—net	**(31,998)**	589	11,853
Gas costs and other regulatory assets/liabilities—net	**(4,789)**	676	7,531
Storage gas	**(43,136)**	(35,295)	(53,033)
Other prepayments—principally taxes	**(1,531)**	1,243	14,414
Accounts payable and other accrued liabilities	**2,212**	20,808	36,699
Wages payable	**386**	(3,438)	1,112
Customer deposits and advance payments	**(2,578)**	37,723	3,404
Accrued taxes	**(4,725)**	(2,939)	7,928
Accrued interest	**379**	138	(246)
Deferred purchased gas costs—net	**(23,550)**	27,698	(5,608)
Other current assets	**(11,607)**	(9,879)	93
Other current liabilities	**5,694**	465	(339)
Other—net	**(756)**	(8,572)	2,844
Net Cash Provided by Operating Activities of Continuing Operations	**86,807**	235,593	240,880
Net Cash Used in Operating Activities of Discontinued Operations	**(1,100)**	(3,095)	(3,212)
Net Cash Provided by Operating Activities	**85,707**	232,498	237,668
FINANCING ACTIVITIES			
Common stock issued	**2,851**	567	50
Long-term debt issued	**77,692**	60,593	37,800
Long-term debt retired	**(75,136)**	(60,665)	(36,109)
Debt issuance costs	**(796)**	(453)	(879)
Notes payable issued (retired)—net	**136,500**	(54,758)	(71,028)
Dividends on common stock	**(65,338)**	(64,024)	(62,746)
Other financing activities—net	**(757)**	(429)	389
Net Cash Provided by (Used in) Financing Activities of Continuing Operations	**75,016**	(119,169)	(132,523)
Net Cash Used in Financing Activities of Discontinued Operations	**–**	(37)	(79)
Net Cash Provided by (Used in) Financing Activities	**75,016**	(119,206)	(132,602)
INVESTING ACTIVITIES			
Capital expenditures (excluding Allowance for Funds Used During Construction)	**(159,757)**	(112,768)	(108,388)
Net proceeds from sale of carried interest in real estate	**–**	–	6,414
Other investing activities—net	**(2,179)**	(2,025)	(821)
Net Cash Used in Investing Activities of Continuing Operations	**(161,936)**	(114,793)	(102,795)
Net Cash Provided by (Used in) Investing Activities of Discontinued Operations	**721**	(244)	(154)
Net Cash Used in Investing Activities	**(161,215)**	(115,037)	(102,949)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(492)**	(1,745)	2,117
Cash and Cash Equivalents at Beginning of Year	**4,842**	6,587	4,470
Cash and Cash Equivalents at End of Year	**$ 4,350**	$ 4,842	$ 6,587
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
Income taxes paid	**$ 58,848**	$ 57,322	$ 22,073
Interest paid	**$ 47,215**	$ 42,031	$ 43,355
SUPPLEMENTAL DISCLOSURES OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Extinguishment of project debt financing	**$ 2,692**	$ 16,447	$ –
Capital expenditures included in accounts payable and other accrued liabilities	**$ (1,243)**	$ 5,551	$ 4,897
Note used to finance capital expenditures	**$ 2,982**	$ –	$ –

The accompanying notes are an integral part of these statements.

WGL Holdings, Inc.
Consolidated Statements of Capitalization
Part II
Item 8. Financial Statements and Supplementary Data (continued)

	September 30,			
(In thousands, except shares)	**2006**		2005	
Common Shareholders' Equity				
Common stock, no par value, 120,000,000 shares authorized, 48,878,499 and 48,704,340 shares issued, respectively	**$ 477,671**		$ 472,974	
Paid-in capital	**8,178**		6,142	
Retained earnings	**440,587**		418,649	
Accumulated other comprehensive loss, net of taxes	**(4,629)**		(3,773)	
Total Common Shareholders' Equity	**921,807**	**60.4%**	893,992	59.3%
Preferred Stock				
WGL Holdings, Inc., without par value, 3,000,000 shares authorized, none issued	**–**		–	
Washington Gas Light Company, without par value, 1,500,000 shares authorized—issued and outstanding:				
$4.80 series, 150,000 shares	**15,000**		15,000	
$4.25 series, 70,600 shares	**7,173**		7,173	
$5.00 series, 60,000 shares	**6,000**		6,000	
Total Preferred Stock	**28,173**	**1.8%**	28,173	1.9%
Long-Term Debt				
Washington Gas Light Company Unsecured Medium-Term Notes				
Due fiscal year 2008, 6.51% to 6.61%	**20,100**		20,100	
Due fiscal year 2008, 7.31%	**–**		25,000	
Due fiscal year 2009, 5.49% to 6.92%	**75,000**		75,000	
Due fiscal year 2010, 7.50% to 7.70%	**24,000**		24,000	
Due fiscal year 2011, 6.64%	**30,000**		30,000	
Due fiscal year 2012, 5.90% to 6.05%	**77,000**		77,000	
Due fiscal year 2014, 4.88% to 5.17%	**67,000**		67,000	
Due fiscal year 2015, 4.83%	**20,000**		20,000	
Due fiscal year 2016, 5.17%	**25,000**		–	
Due fiscal year 2023, 6.65%	**20,000**		20,000	
Due fiscal year 2025, 5.44%	**40,500**		40,500	
Due fiscal year 2026, 6.15%	**–**		50,000	
Due fiscal year 2027, 6.40% to 6.82%	**125,000**		125,000	
Due fiscal year 2028, 6.57% to 6.85%	**52,000**		52,000	
Due fiscal year 2030, 7.50%	**8,500**		8,500	
Due fiscal year 2036, 5.70% to 5.78%	**50,000**		–	
Total Unsecured Medium-Term Notes	**634,100**		634,100	
Other long-term debt	**3,235**		227	
Unamortized discount	**(202)**		(55)	
Less—current maturities	**60,994**		50,122	
Total Long-Term Debt	**576,139**	**37.8%**	584,150	38.8%
Total Capitalization	**$1,526,119**	**100.0%**	$1,506,315	100.0%

The accompanying notes are an integral part of these statements.

WGL Holdings, Inc.
Consolidated Statements of Common Shareholders' Equity
Part II
Item 8. Financial Statements and Supplementary Data (continued)

(In thousands, except shares)	Common Stock Issued Shares	Common Stock Issued Amount	Paid-In Capital	Retained Earnings	Deferred Compensation	Accumulated Other Comprehensive Loss, Net of Taxes	Treasury Stock	Total
Balance at September 30, 2003	48,650,635	$471,497	$2,582	$345,927	$(32)	$ (716)	$(1,040)	$818,218
Net income	–	–	–	96,637	–	–	–	96,637
Minimum pension liability adjustment	–	–	–	–	–	(753)	–	(753)
Comprehensive income								95,884
Stock-based compensation	1,872	50	1,207	–	27	–	1,040	2,324
Dividends declared on common stock ($1.2950 per share)	–	–	–	(63,002)	–	–	–	(63,002)
Balance at September 30, 2004	48,652,507	471,547	3,789	379,562	(5)	(1,469)	–	853,424
Net income	–	–	–	103,493	–	–	–	103,493
Minimum pension liability adjustment	–	–	–	–	–	(2,304)	–	(2,304)
Comprehensive income								101,189
Stock-based compensation	51,833	1,427	2,353	–	5	–	–	3,785
Dividends declared on common stock ($1.3225 per share)	–	–	–	(64,406)	–	–	–	(64,406)
Balance at September 30, 2005	48,704,340	472,974	6,142	418,649	–	(3,773)	–	893,992
Net income	–	–	–	87,578	–	–	–	87,578
Minimum pension liability adjustment	–	–	–	–	–	(856)	–	(856)
Comprehensive income								86,722
Stock-based compensation	174,159	4,697	2,036	–	–	–	–	6,733
Dividends declared on common stock ($1.345 per share)	–	–	–	(65,640)	–	–	–	(65,640)
Balance at September 30, 2006	**48,878,499**	**$477,671**	**$8,178**	**$440,587**	**$ –**	**$(4,629)**	**$ –**	**$921,807**

The accompanying notes are an integral part of these statements.

Washington Gas Light Company
Statements of Income
Part II
Item 8. Financial Statements and Supplementary Data (continued)

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
OPERATING REVENUES			
Utility	**$1,637,491**	$1,402,905	$1,293,675
Non-utility	**632**	1,269	1,523
Total Operating Revenues	**1,638,123**	1,404,174	1,295,198
OPERATING EXPENSES			
Utility cost of gas	**1,031,650**	796,413	694,639
Operation and maintenance	**238,086**	243,139	231,861
Depreciation and amortization	**91,962**	89,140	90,809
General taxes and other assessments	**96,523**	98,358	86,200
Total Operating Expenses	**1,458,221**	1,227,050	1,103,509
OPERATING INCOME	**179,902**	177,124	191,689
Other Income (Expenses)—Net	**1,855**	1,082	1,586
Interest Expense			
Interest on long-term debt	**40,622**	41,049	41,822
Other—net	**3,392**	551	1,319
Total Interest Expense	**44,014**	41,600	43,141
INCOME BEFORE INCOME TAXES	**137,743**	136,606	150,134
INCOME TAXES	**51,902**	47,393	53,544
NET INCOME (BEFORE PREFERRED STOCK DIVIDENDS)	**85,841**	89,213	96,590
Dividends on preferred stock	**1,320**	1,320	1,320
NET INCOME (APPLICABLE TO COMMON STOCK)	**$ 84,521**	$ 87,893	$ 95,270

The accompanying notes are an integral part of these statements.

Washington Gas Light Company
Balance Sheets
Part II

Item 8. Financial Statements and Supplementary Data (continued)

	September 30,	
(In thousands)	**2006**	2005
ASSETS		
Property, Plant and Equipment		
At original cost	**$2,920,552**	$2,756,638
Accumulated depreciation and amortization	**(864,310)**	(794,286)
Net property, plant and equipment	**2,056,242**	1,962,352
Current Assets		
Cash and cash equivalents	**4,086**	3,054
Receivables		
Accounts receivable	**55,757**	77,117
Gas costs and other regulatory assets	**14,609**	9,711
Unbilled revenues	**18,337**	16,476
Allowance for doubtful accounts	**(16,543)**	(14,981)
Net receivables	**72,160**	88,323
Materials and supplies—principally at average cost	**18,302**	16,823
Storage gas—at cost (first-in, first-out)	**217,242**	194,104
Deferred income taxes	**11,313**	12,957
Other prepayments—principally taxes	**11,395**	11,059
Receivables from associated companies	**1,140**	8,131
Other	**10,560**	106
Total current assets	**346,198**	334,557
Deferred Charges and Other Assets		
Regulatory assets		
Gas costs	**11,950**	–
Other	**64,833**	64,236
Prepaid qualified pension benefits	**75,865**	75,586
Other	**7,899**	9,404
Total deferred charges and other assets	**160,547**	149,226
Total Assets	**$2,562,987**	$2,446,135
CAPITALIZATION AND LIABILITIES		
Capitalization		
Common shareholder's equity	**$ 857,353**	$ 835,757
Preferred stock	**28,173**	28,173
Long-term debt	**574,139**	584,150
Total capitalization	**1,459,665**	1,448,080
Current Liabilities		
Current maturities of long-term debt	**60,000**	50,122
Notes payable	**72,775**	10,409
Accounts payable and other accrued liabilities	**137,505**	149,706
Wages payable	**13,533**	13,196
Accrued interest	**3,298**	2,919
Dividends declared	**16,826**	16,524
Customer deposits and advance payments	**49,495**	33,880
Gas costs and other regulatory liabilities	**14,212**	14,103
Accrued taxes	**8,676**	10,261
Payables to associated companies	**17,332**	18,598
Other	**5,163**	281
Total current liabilities	**398,815**	319,999
Deferred Credits		
Unamortized investment tax credits	**13,140**	14,033
Deferred income taxes	**297,213**	290,375
Accrued pensions and benefits	**44,082**	40,916
Asset retirement obligations	**26,554**	–
Regulatory liabilities		
Accrued asset removal costs	**268,922**	272,124
Gas costs	**–**	11,600
Other	**17,205**	15,946
Other	**37,391**	33,062
Total deferred credits	**704,507**	678,056
Commitments and Contingencies (Note 15)		
Total Capitalization and Liabilities	**$2,562,987**	$2,446,135

The accompanying notes are an integral part of these statements.

Washington Gas Light Company
Statements of Cash Flows
Part II
Item 8. Financial Statements and Supplementary Data (continued)

(In thousands)	Years Ended September 30, 2006	2005	2004
OPERATING ACTIVITIES			
Net income (before preferred stock dividends)	**$ 85,841**	$ 89,213	$ 96,590
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES			
Depreciation and amortization:			
Per Statements of Income	**91,962**	89,140	90,809
Charged to other accounts	**3,765**	4,319	4,339
Deferred income taxes—net	**12,295**	2,764	30,364
Amortization of investment tax credits	**(893)**	(893)	(892)
Accrued/deferred pension cost	**(1,509)**	(4,977)	(5,198)
Other non-cash charges (credits)—net	**3,687**	2,872	1,769
CHANGES IN ASSETS AND LIABILITIES			
Accounts receivable, unbilled revenues and receivables from associated companies—net	**28,052**	(15,624)	(1,910)
Gas costs and other regulatory assets/liabilities—net	**(4,789)**	676	7,531
Storage gas	**(23,138)**	(28,908)	(40,780)
Other prepayments—principally taxes	**(336)**	(1,416)	9,340
Accounts payable and other accrued liabilities, including payables to associated companies	**(16,982)**	20,707	21,039
Wages payable	**337**	(3,518)	1,091
Customer deposits and advance payments	**15,615**	19,430	3,404
Accrued taxes	**(1,585)**	(3,161)	6,996
Accrued interest	**379**	138	(246)
Deferred purchased gas costs—net	**(23,550)**	27,698	(5,608)
Other current assets	**(11,933)**	(1,755)	(2,243)
Other current liabilities	**4,882**	(341)	(874)
Other—net	**757**	(8,997)	2,490
Net Cash Provided by Operating Activities	**162,857**	187,367	218,011
FINANCING ACTIVITIES			
Long-term debt issued	**77,692**	60,593	37,800
Long-term debt retired	**(75,136)**	(60,665)	(36,109)
Debt issuance costs	**(796)**	(453)	(879)
Notes payable issued (retired)—net	**62,366**	(8,290)	(46,527)
Dividends on common stock and preferred stock	**(66,658)**	(65,343)	(64,065)
Other financing activities—net	**(757)**	(430)	(270)
Net Cash Used in Financing Activities	**(3,289)**	(74,588)	(110,050)
INVESTING ACTIVITIES			
Capital expenditures (excluding Allowance for Funds Used During Construction)	**(156,357)**	(111,098)	(107,861)
Other investing activities—net	**(2,179)**	(2,025)	(821)
Net Cash Used in Investing Activities	**(158,536)**	(113,123)	(108,682)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**1,032**	(344)	(721)
Cash and Cash Equivalents at Beginning of Year	**3,054**	3,398	4,119
Cash and Cash Equivalents at End of Year	**$ 4,086**	$ 3,054	$ 3,398
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION			
Income taxes paid	**$ 42,803**	$ 48,449	$ 16,665
Interest paid	**$ 42,937**	$ 40,181	$ 42,352
SUPPLEMENTAL DISCLOSURES OF NON-CASH INVESTING AND FINANCING ACTIVITIES			
Extinguishment of project debt financing	**$ 2,692**	$ 16,447	$ –
Capital expenditures included in accounts payable and other accrued liabilities	**$ (702)**	$ 5,042	$ 4,964

The accompanying notes are an integral part of these statements.

Washington Gas Light Company
Statements of Capitalization
Part II
Item 8. Financial Statements and Supplementary Data (continued)

	September 30,			
(In thousands, except shares)	**2006**		2005	
Common Shareholder's Equity				
Common stock, $1 par value, 80,000,000 shares authorized, 46,479,536 shares issued	**$ 46,479**		$ 46,479	
Paid-in capital	**458,907**		455,336	
Retained earnings	**356,596**		337,715	
Accumulated other comprehensive loss, net of taxes	**(4,629)**		(3,773)	
Total Common Shareholder's Equity	**857,353**	**58.7%**	835,757	57.7%
Preferred Stock				
Washington Gas Light Company, without par value, 1,500,000 shares authorized—issued and outstanding:				
$4.80 series, 150,000 shares	**15,000**		15,000	
$4.25 series, 70,600 shares	**7,173**		7,173	
$5.00 series, 60,000 shares	**6,000**		6,000	
Total Preferred Stock	**28,173**	**1.9%**	28,173	2.0%
Long-Term Debt				
Washington Gas Light Company Unsecured Medium-Term Notes				
Due fiscal year 2008, 6.51% to 6.61%	**20,100**		20,100	
Due fiscal year 2008, 7.31%	**–**		25,000	
Due fiscal year 2009, 5.49% to 6.92%	**75,000**		75,000	
Due fiscal year 2010, 7.50% to 7.70%	**24,000**		24,000	
Due fiscal year 2011, 6.64%	**30,000**		30,000	
Due fiscal year 2012, 5.90% to 6.05%	**77,000**		77,000	
Due fiscal year 2014, 4.88% to 5.17%	**67,000**		67,000	
Due fiscal year 2015, 4.83%	**20,000**		20,000	
Due fiscal year 2016, 5.17%	**25,000**		–	
Due fiscal year 2023, 6.65%	**20,000**		20,000	
Due fiscal year 2025, 5.44%	**40,500**		40,500	
Due fiscal year 2026, 6.15%	**–**		50,000	
Due fiscal year 2027, 6.40% to 6.82%	**125,000**		125,000	
Due fiscal year 2028, 6.57% to 6.85%	**52,000**		52,000	
Due fiscal year 2030, 7.50%	**8,500**		8,500	
Due fiscal year 2036, 5.70% to 5.78%	**50,000**		–	
Total Unsecured Medium-Term Notes	**634,100**		634,100	
Other long-term debt	**91**		227	
Unamortized discount	**(52)**		(55)	
Less—current maturities	**60,000**		50,122	
Total Long-Term Debt	**574,139**	**39.4%**	584,150	40.3%
Total Capitalization	**$1,459,665**	**100.0%**	$1,448,080	100.0%

The accompanying notes are an integral part of these statements.

Washington Gas Light Company
Statements of Common Shareholder's Equity
Part II
Item 8. Financial Statements and Supplementary Data (continued)

(In thousands, except shares)	Common Stock Issued Shares	Common Stock Issued Amount	Paid-In Capital	Retained Earnings	Deferred Compensation	Accumulated Other Comprehensive Loss, Net of Taxes	Total
Balance at September 30, 2003	46,479,536	$46,479	$450,813	$281,958	$(32)	$ (716)	$778,502
Net income	–	–	–	96,590	–	–	96,590
Minimum pension liability adjustment	–	–	–	–	–	(753)	(753)
Comprehensive income							95,837
Stock-based compensation[(a)]	–	–	1,587	–	27	–	1,614
Dividends declared:							
Common stock ($1.2950 per share)	–	–	–	(63,001)	–	–	(63,001)
Preferred stock	–	–	–	(1,320)	–	–	(1,320)
Balance at September 30, 2004	46,479,536	46,479	452,400	314,227	(5)	(1,469)	811,632
Net income	–	–	–	89,213	–	–	89,213
Minimum pension liability adjustment	–	–	–	–	–	(2,304)	(2,304)
Comprehensive income							86,909
Stock-based compensation[(a)]	–	–	2,936	–	5	–	2,941
Dividends declared:							
Common stock ($1.3225 per share)	–	–	–	(64,405)	–	–	(64,405)
Preferred stock	–	–	–	(1,320)	–	–	(1,320)
Balance at September 30, 2005	46,479,536	46,479	455,336	337,715	–	(3,773)	835,757
Net income	–	–	–	85,841	–	–	85,841
Minimum pension liability adjustment	–	–	–	–	–	(856)	(856)
Comprehensive income							84,985
Stock-based compensation[(a)]	–	–	3,571	–	–	–	3,571
Dividends declared:							
Common stock ($1.3450 per share)	–	–	–	(65,640)	–	–	(65,640)
Preferred stock	–	–	–	(1,320)	–	–	(1,320)
Balance at September 30, 2006	**46,479,536**	**$46,479**	**$458,907**	**$356,596**	**$ –**	**$(4,629)**	**$857,353**

[(a)] *Stock-based compensation is based on the stock awards of WGL Holdings that are allocated to Washington Gas Light Company for its pro-rata share.*

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ACCOUNTING POLICIES

GENERAL

WGL Holdings, Inc. (WGL Holdings) is a holding company that owns all of the shares of common stock of Washington Gas Light Company (Washington Gas), a regulated natural gas utility, and all of the shares of common stock of Washington Gas Resources Corporation (Washington Gas Resources), Hampshire Gas Company (Hampshire) and Crab Run Gas Company. Washington Gas Resources owns all of the shares of common stock of various unregulated, energy-related businesses. Except where the content clearly indicates otherwise, "WGL Holdings," "we," "us" or "our" refers to the holding company or the consolidated entity of WGL Holdings and all of its subsidiaries.

NATURE OF OPERATIONS

Our core business is the delivery and sale of natural gas through Washington Gas. We also offer retail energy-related products and services that are closely related to our core business. The majority of these energy-related activities are performed by wholly owned unregulated subsidiaries of Washington Gas Resources.

Washington Gas is a regulated public utility that delivers and sells natural gas to over one million customers primarily in Washington, D.C., and the surrounding metropolitan areas in Maryland and Virginia. Deliveries to firm residential and commercial customers accounted for 76.8 percent of the total therms delivered by Washington Gas in fiscal year 2006. Deliveries to interruptible customers accounted for 16.3 percent and deliveries to customers who use natural gas to generate electricity accounted for 6.9 percent. Washington Gas does not depend on any one customer or group of customers to derive income. Hampshire operates an underground natural gas storage facility that provides services exclusively to Washington Gas. Hampshire is regulated under a cost of service tariff by the Federal Energy Regulatory Commission (FERC). Both Washington Gas and Hampshire comprise our regulated utility segment.

Washington Gas Resources owns our unregulated subsidiaries. These unregulated operations include retail energy-marketing provided by Washington Gas Energy Services (WGEServices), as well as commercial heating, ventilating and air conditioning (HVAC) products and services provided by Washington Gas Energy Systems, Inc. (WGESystems). On September 29, 2006, Washington Gas Resources sold all of the outstanding shares of common stock of its wholly owned subsidiary, American Combustion Industries (ACI). ACI is presented as a discontinued operation within WGL Holdings' consolidated financial statements.

CONSOLIDATION OF FINANCIAL STATEMENTS

The consolidated financial statements include the accounts of WGL Holdings and its subsidiaries during the fiscal years reported. Intercompany transactions have been eliminated. Certain reclassifications have been made to the consolidated financial statements of WGL Holdings and the financial statements of Washington Gas for all prior fiscal years presented to conform to the presentation in fiscal year 2006. These reclassifications reflect the discontinued operations of ACI as presented on WGL Holdings' consolidated financial statements (refer to Note 2—*Discontinued Operations*), as well as changes to the presentation of the statements of income for both WGL Holdings and Washington Gas.

During fiscal year 2006, we revised the format of our statements of income, in part, to present our results of operations without sub-captions for both our utility and non-utility operations. The primary effect of this change in format was to combine the operating revenues and expenses for our utility and non-utility operations, thereby resulting in a singular presentation of operating income. The change in format also reflects an increase in operating income as a result of excluding income taxes from utility and non-utility operating expenses. Under the new format, we combined all income taxes into one caption labeled "Income taxes" which is presented below operating income. None of these reclassifications had any effect on the net income or earnings per share of WGL Holdings or the net income of Washington Gas.

USE OF ESTIMATES IN THE PREPARATION OF FINANCIAL STATEMENTS

In accordance with Generally Accepted Accounting Principles in the United States of America (GAAP), we make certain estimates and assumptions regarding: *(i)* reported amounts of assets and liabilities; *(ii)* disclosure of contingent assets and liabilities at the date of the financial statements and *(iii)* reported amounts of revenues, revenues subject to refund, and expenses during the reporting period. Actual results could differ from those estimates.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment (comprised principally of utility plant) is stated at original cost, including labor, materials, taxes and overhead costs incurred during the construction period. The cost of utility and other plant of Washington Gas includes an allowance for funds used during construction (AFUDC) that is calculated under a formula prescribed by the FERC. Washington Gas capitalizes AFUDC as a component of construction overhead. The fiscal year 2006, 2005 and 2004 before-tax rates for AFUDC were 5.54 percent, 5.12 percent and 1.98 percent, respectively. Washington Gas capitalized AFUDC of $680,000 during the fiscal year ended September 30, 2006, excluding offsets of $38,000 representing adjustments to AFUDC for capital items or projects that were discontinued and expensed. Capitalized AFUDC for fiscal years 2005 and 2004 was $314,000 and $94,700, respectively, excluding offsets of $185,000 and $20,000, respectively.

Washington Gas accrues an annual amount of asset removal costs through depreciation expense with a corresponding credit to "Regulatory liabilities—Accrued asset removal costs." The amount of asset removal costs accrued each year for a particular asset is equal to the total estimated cost of removal divided by the useful life of the related asset. Additionally, when Washington Gas retires depreciable utility plant and equipment, it charges the associated original costs to "Accumulated depreciation and amortization" and any related removal costs incurred are charged to "Regulatory liabilities—Accrued asset removal costs." In the rate setting process, the liability for asset removal costs is treated as a reduction to the net rate base upon which Washington Gas has the opportunity to earn its allowed rate of return. At September 30, 2006, in conjunction with its implementation of Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), Washington Gas recognized a liability for its legal asset retirement obligations (AROs) and reclassified a portion of its accrued asset removal costs from "Regulatory liabilities—Accrued asset removal costs" to "Asset retirement obligations," a non-regulatory deferred credit (refer to *"Newly Implemented Accounting Standards"* for a further discussion of this matter).

Washington Gas charges maintenance and repairs to operating expenses, except those charges applicable to transportation and power-operated equipment, which it allocates to operating expenses, construction and other accounts based on the use of the equipment. Washington Gas capitalizes betterments and renewal costs, and calculates depreciation applicable to its utility gas plant in service primarily using a straight-line method over the estimated remaining life of the plant. The composite depreciation and amortization rate of the regulated utility segment was 3.44 percent during fiscal year 2006, and 3.48 percent during fiscal years 2005 and 2004. In accordance with regulatory requirements, such rates include a component related to asset removal costs for Washington Gas. Washington Gas periodically reviews the adequacy of its depreciation rates by considering estimated remaining lives and other factors. Refer to Note 15—*Commitments and Contingencies* for a discussion of depreciation-related contingencies.

At both September 30, 2006 and 2005, 99.8 percent of WGL Holdings' consolidated original cost of property, plant and equipment was related to the regulated utility segment as shown below.

Property, Plant and Equipment at Original Cost

At September 30,	**2006**		2005	
(In millions)	**Dollars**	**%**	Dollars	%
Regulated utility segment				
Distribution, transmission and storage	**$2,585.0**	**87.6**	$2,460.0	88.5
General, miscellaneous and intangibles	**296.6**	**10.1**	266.5	9.6
Construction work in progress (CWIP)	**62.5**	**2.1**	48.4	1.7
Total regulated utility segment	**2,944.1**	**99.8**	2,774.9	99.8
Unregulated segments	**5.9**	**0.2**	5.0	0.2
Total	**$2,950.0**	**100.0**	$2,779.9	100.0

OPERATING LEASES

We have classified the lease of our corporate headquarters as an operating lease under Statement of Financial Accounting Standards (SFAS) No. 13, *Accounting for Leases*. In accordance with FASB Technical Bulletins No. 88-1 and 85-3, we amortize to rent expense the total of all scheduled lease payments (including lease payment escalations) and tenant allowances on a straight-line basis over the term of the lease. For this purpose, the lease term began on the date when the lessor commenced constructing the leasehold

improvements which allowed us to occupy our corporate headquarters. These leasehold improvement costs are classified as "Property, Plant and Equipment" on the Balance Sheets, and are being amortized to depreciation and amortization expense on a straight-line basis over the term of the 15-year non-cancelable period of the lease.

REGULATED OPERATIONS

Washington Gas accounts for its regulated operations in accordance with SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, as amended and supplemented. This standard includes accounting principles for companies whose rates are determined by independent third-party regulators. When setting rates, regulators often make decisions which require companies to record costs as expense (or defer costs or revenues) in different periods than may be appropriate for unregulated enterprises. When this occurs, Washington Gas defers the associated costs as assets (regulatory assets) on its balance sheet and records them as expenses on its income statement as it collects revenues through customers' rates. Further, regulators can also impose liabilities upon a company for amounts previously collected from customers and for recovery of costs that are expected to be incurred in the future (regulatory liabilities).

At September 30, 2006 and 2005, Washington Gas had recorded the following regulatory assets and liabilities on its balance sheets. These assets and liabilities will be recognized as revenues and expenses in future periods as they are reflected in customers' rates.

Regulatory Assets and Liabilities

(In millions)	Regulatory Assets		Regulatory Liabilities	
At September 30,	**2006**	2005	**2006**	2005
Accrued asset removal costs	**$ –**	$ –	**$268.9**	$272.1
Income tax-related amounts due from/to customers	**34.1**	34.8	**10.3**	7.8
Least-cost planning costs	**1.8**	4.1	**–**	–
Losses/gains on issuance and extinguishments of debt and interest-rate derivative instruments	**9.6**	9.3	**2.1**	1.8
Other post-retirement benefit costs	**9.3**	8.2	**–**	–
Gas costs:				
Due from customers	**11.7**	9.7	**–**	–
Due to customers	**–**	–	**14.2**	14.1
Deferred	**12.0**	–	**–**	11.6
Deferred pension costs/income	**2.7**	–	**–**	2.0
Deferred gain on sale of assets	**–**	–	**3.8**	4.1
Environmental response costs	**3.0**	3.2	**–**	–
Rights-of-way fees	**3.1**	2.8	**–**	–
RNA billing mechanism	**2.9**	–	**–**	–
Deferred regulatory and other expenses	**1.7**	1.8	**1.0**	0.3
Total	**$91.9**	$73.9	**$300.3**	$313.8

Regulatory assets for gas costs due from customers and a Revenue Normalization Adjustment (RNA) billing mechanism (refer to Note 15—*Commitments and Contingencies*) are reported on our balance sheets under the caption "Gas costs and other regulatory assets." Deferred gas costs and other regulatory assets are reported on our balance sheets under the captions "Regulatory assets—Gas costs" and "Regulatory assets—Other," respectively. Regulatory liabilities for gas costs due to customers are reported on our balance sheets under the caption "Gas costs and other regulatory liabilities." Accrued asset removal costs, deferred gas costs and other regulatory liabilities are reported on our balance sheets under the captions "Regulatory liabilities—Accrued asset removal costs," "Regulatory liabilities—Gas costs" and "Regulatory liabilities—Other," respectively. With the exception of gas costs due from customers and deferred gas costs, there are no material regulatory assets that reflect an outlay of cash by Washington Gas for which Washington Gas does not earn its overall rate of return. Washington Gas is allowed to recover and is required to pay, using short-term interest rates, the carrying costs related to gas costs due from and to its customers in the District of Columbia and Virginia jurisdictions.

As required by SFAS No. 71, Washington Gas monitors its regulatory and competitive environment to determine whether the recovery of its regulatory assets continues to be probable. If Washington Gas were to determine that recovery of these assets is no

longer probable, it would write off the assets against earnings. We have determined that SFAS No. 71 continues to apply to our regulated operations, and the recovery of our regulatory assets is probable.

The losses/gains on the issuance and extinguishment of debt and interest-rate derivative instruments include unamortized balances from transactions executed in prior fiscal years, and also include transactions generated in fiscal year 2006, as described more fully in Note 7—*Derivative and Weather-Related Instruments*. These transactions create gains and losses that are amortized over the remaining life of the debt as prescribed by regulatory accounting requirements.

CASH AND CASH EQUIVALENTS

We consider all investments with original maturities of three months or less to be cash equivalents. We did not have any restrictions on our cash balances that would impact the payment of dividends by WGL Holdings or our subsidiaries as of September 30, 2006.

REVENUE AND COST RECOGNITION

Regulated Utility Operations

Revenues. For regulated deliveries of natural gas, Washington Gas reads meters and bills customers on a cycle basis since all meters economically cannot be read on the last day of the month. Washington Gas accrues revenues for gas delivered, but not yet billed, at the end of each accounting period. Such revenues are recognized as unbilled revenues that are adjusted in subsequent periods when actual meter readings are taken.

Cost of Gas. Washington Gas' jurisdictional tariffs contain mechanisms that provide for the recovery of the cost of gas paid to suppliers on behalf of firm customers, including certain pipeline transportation and storage capacity charges. Under these mechanisms, Washington Gas periodically adjusts its firm customers' rates to reflect increases and decreases in these costs. Annually, Washington Gas reconciles the difference between the total gas costs collected from firm customers and the total gas costs paid to suppliers. Washington Gas defers any excess or deficiency and either recovers it from, or refunds it to, customers over a subsequent twelve-month period through an actual cost adjustment billing mechanism. The balance sheet captions "Gas costs and other regulatory assets," "Gas costs and other regulatory liabilities," "Regulatory assets—Gas costs" and "Regulatory liabilities—Gas costs" include amounts related to these reconciliations.

Transportation Gas Imbalance. Interruptible shippers and third-party marketer shippers transport gas on Washington Gas' pipeline facilities as part of the unbundled services that it offers. The delivered volumes of gas from third-party shippers into Washington Gas' pipeline facilities often do not equal the volumes delivered out of the pipeline system to the customers, resulting in transportation gas imbalances. These imbalances are usually short-term in duration, and Washington Gas monitors the activity and regularly notifies the shippers when their accounts have an imbalance. In accordance with regulatory treatment, Washington Gas does not record assets or liabilities associated with gas volumes related to these transportation imbalances but, rather, reflects the economic impact in its actual cost adjustment balance calculations, thereby eliminating any profit or loss that would occur as a result of the imbalance. This regulatory treatment results in recognizing an adjustment to a regulatory asset or a regulatory liability for Washington Gas' value of the imbalance. The regulatory treatment combines the imbalance for all marketers into a single "net" adjustment to the regulatory asset or liability. The imbalances are settled in gas volumes and, when this occurs, the impact on the actual cost adjustment balance is reversed. Due to this regulatory treatment at Washington Gas, there is no elimination of assets or liabilities when the companies are consolidated.

Washington Gas also engages an asset manager to operate its pipeline and storage capacity, and to assist in the acquisition of natural gas supply. From time to time, the asset manager will utilize the upstream pipeline capacity reserved by Washington Gas and the capacity from Washington Gas' pipeline system for the asset manager's own purposes. Washington Gas also self-manages a small portion of these type of assets. These off-system sales generated by the asset manager and Washington Gas are accounted for under regulated margin-sharing arrangements that vary by jurisdiction whereby a significant portion of these revenues is shared with Washington Gas' customers as a reduction in natural gas costs, otherwise recoverable from firm customers. Washington Gas also designates portions of its pipeline, peaking and storage capacity to third-party marketers, under a program approved by relevant regulatory bodies, in connection with its customer choice programs.

Non-Utility Operations

Retail Energy-Marketing. WGEServices, our retail energy-marketing subsidiary, sells natural gas and electricity on an unregulated basis to residential, commercial and industrial customers both inside and outside the Washington Gas service territory. WGEServices recognizes revenue based on contractual billing amounts plus accruals for the natural gas and electricity commodities that are delivered but unbilled.

WGEServices enters into indexed or fixed-rate contracts with residential, commercial and industrial customers, for sales of natural gas and electricity. Customer contracts that typically have terms less than 24 months, but may extend up to five years, allow WGEServices to bill customers based upon metered gas and electricity usage, measured on a cycle basis, at customer premises or based on quantities delivered to the local utility, either of which may vary by month.

WGEServices procures natural gas and electricity supply under contract structures in which it assembles the various components of supply from multiple suppliers to match its customer requirements. The cost of natural gas and electricity for these purchases is recorded using the contracted volumes and prices.

Heating, Ventilating and Air Conditioning. An unregulated subsidiary of Washington Gas Resources, WGESystems designs, renovates and services mechanical HVAC systems for commercial and governmental customers under construction contracts. We recognize income and expenses for all contracts using the percentage-of-completion method.

RATE REFUNDS DUE TO CUSTOMERS

If Washington Gas were to file a request with a regulatory commission to modify customers' rates, it could, depending on the jurisdiction, charge customers new rates, subject to refund, until the regulatory commission renders a final decision on the amount of the authorized change in rates. During this interim period, Washington Gas would potentially record a provision for a rate refund based on the difference between the amount it collected in rates subject to refund and the amount it expected to recover pending the final regulatory decision. Similarly, Washington Gas periodically records provisions for rate refunds related to other transactions. Actual results for these regulatory contingencies are often difficult to predict and could differ significantly from the estimates reflected in the financial statements. When necessary, Washington Gas establishes a liability for an estimated refund to customers. Refer to Note 15—*Commitments and Contingencies* for a further discussion of regulatory matters and related contingencies.

REACQUISITION OF LONG-TERM DEBT

Washington Gas defers gains or losses resulting from the reacquisition of long-term debt for financial reporting purposes, and amortizes them over future periods as adjustments to interest expense in accordance with established regulatory practice. For income tax purposes, Washington Gas recognizes these gains and losses when they are incurred.

WEATHER-RELATED INSTRUMENTS

We own certain weather related instruments, such as a weather insurance policy and heating degree days (HDDs) derivatives and we account for them under the guidelines issued by the Emerging Issues Task Force (EITF) of the FASB in Issue No. 99-2. Benefits are recognized to the extent actual HDDs fall below the contracted HDDs for each instrument. Expenses of the products are amortized based on the pattern of normal HDDs over the period of the terms of the respective weather-related instruments. For the weather-related instruments of Washington Gas, the premium expense and any benefits that are derived are not considered in establishing retail rates. Refer to Note 7—*Derivative and Weather-Related Instruments* for a further discussion of our weather-related instruments.

CONCENTRATION OF CREDIT RISK

Regulated Utility Segment

The revenues of the regulated utility segment accounted for approximately 62.1 percent of WGL Holdings' total consolidated revenues for the fiscal year ended September 30, 2006. Washington Gas has a relatively low concentration of credit risk with respect to its customer base due to its large number of customers, none of which is singularly large as a percentage of Washington Gas' total customer base. Certain suppliers that sell natural gas to Washington Gas have either relatively low credit ratings or are not rated by major credit rating agencies. In the event of a supplier's failure to deliver contracted volumes of gas, Washington Gas may need to

replace those volumes at prevailing market prices, which may be higher than the original transaction prices, and pass these costs through to its sales customers under the purchased gas cost adjustment mechanisms.

Retail Energy-Marketing Segment

Certain suppliers that sell natural gas or electricity to WGEServices have either relatively low credit ratings or are not rated by major credit rating agencies. Depending on the ability of these suppliers to deliver natural gas or electricity under existing contracts, WGEServices could be financially exposed for the difference between the price at which WGEServices has contracted to buy these commodities, and the replacement cost of these commodities that may need to be purchased. WGEServices has a wholesale supplier credit policy in place that is designed to mitigate wholesale credit risks through a requirement for credit enhancements. In accordance with this policy, WGEServices has obtained credit enhancements from certain of its suppliers. WGEServices continuously monitors the unsecured credit limits it will accept from certain suppliers or their guarantors.

DERIVATIVE ACTIVITIES

We apply the accounting guidelines of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended by SFAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities* and SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* (collectively referred to as SFAS No. 133). SFAS No. 133 requires derivative instruments, including derivative instruments embedded in certain contracts, to be recorded at fair value as either an asset or a liability. Changes in the derivative's fair value are recorded in earnings, unless the derivative meets specific hedge accounting criteria. If the derivative is designated as a fair value hedge, the changes in the fair value of the derivative and the hedged item are recognized in earnings. If the derivative is designated as a cash flow hedge, changes in the fair value of the derivative generally are recorded in other comprehensive income (loss) and recognized in income when the hedged item affects earnings. Additionally in accordance with SFAS No. 133, we formally document, designate and assess the effectiveness of derivatives that are accounted for as hedging instruments. For those derivatives that are associated with the activities of Washington Gas whose costs are likely to be recovered from or refunded to customers in future periods, the corresponding fair value is recorded as a regulatory asset or a regulatory liability, subject to SFAS No. 71, and are reflected in earnings at such time as the related revenues from gas sales are recognized.

We enter into forward contracts and other related transactions for the purchase of natural gas and electricity. A majority of these contracts qualify for normal purchases and sales treatment and are exempt from the mark-to-market accounting requirements of SFAS No. 133.

From time to time, Washington Gas utilizes derivative instruments that are designed to minimize the risk of interest-rate volatility associated with planned issuances of Medium-Term Notes (MTNs). Gains or losses associated with these derivative transactions are deferred as regulatory assets or liabilities and amortized to interest expense in accordance with regulatory accounting requirements.

Refer to Note 7—*Derivative and Weather-Related Instruments* for a further discussion of these transactions.

INCOME TAXES

We account for income taxes in accordance with SFAS No. 109, *Accounting for Income Taxes*. Under SFAS No. 109, we recognize deferred income taxes for all temporary differences between the financial statement basis and the tax basis of assets and liabilities at currently enacted income tax rates.

SFAS No. 109 also requires recognition of the additional deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes of Washington Gas. Regulatory assets or liabilities, corresponding to such additional deferred income tax assets or liabilities, may be recorded to the extent recoverable from or payable to customers through the ratemaking process. Refer to the table under *"Regulated Operations"* above that depicts Washington Gas' regulatory assets and liabilities associated with income taxes due from and to customers at September 30, 2006 and 2005. Amounts applicable to income taxes due from and due to customers primarily represent differences between the book and tax basis of net utility plant in service.

We amortize investment tax credits as reductions to income tax expense over the estimated service lives of the related properties.

Refer to Note 11—*Income Taxes* that provides detailed financial information related to our income taxes.

NEWLY IMPLEMENTED ACCOUNTING STANDARDS

Stock-Based Compensation

Effective October 1, 2005, we adopted SFAS No. 123 (revised 2004), *Share-Based Payment* (SFAS No. 123(R)) which revises SFAS No. 123, and supersedes Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees.* SFAS No. 123(R) requires us to measure and recognize stock-based compensation expense in our financial statements based on the 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 No. 123(R), we recognize compensation expense over the requisite service period for: *(i)* awards granted on or after October 1, 2005 and *(ii)* unvested awards previously granted and outstanding as of October 1, 2005. In addition, we estimate forfeitures over the requisite service period when recognizing compensation expense; these estimates are adjusted to the extent to which actual forfeitures differ, or are expected to materially differ, from such estimates.

Prior to October 1, 2005, we accounted for our share-based payment transactions in accordance with APB Opinion No. 25 and related interpretations. In accordance with APB Opinion No. 25, we did not record compensation expense related to stock option grants in our financial statements. We did record compensation expense over the requisite service period for performance shares awarded to certain key employees based on the market value of our common stock at the end of each reporting period.

The following table depicts the effect of adopting SFAS No. 123(R) on income from continuing operations, net income applicable to common stock and earnings per share for the year ended September 30, 2006. Specifically shown is our reported net income and earnings per share for the year ended September 30, 2006, which reflect compensation expense related to our share-based awards recorded in accordance with SFAS No. 123(R), as compared to net income and earnings per share for the same period that would have been reported had such compensation expense been recorded under APB Opinion No. 25.

WGL Holdings, Inc.
Effect of Adopting SFAS No. 123(R)

	Year Ended September 30, 2006	
(In thousands, except per share data)	**As Reported**	Per APB No. 25
Total stock-based compensation expense (before income taxes)	**$ 4,384**	$ 71
Income from continuing operations	**$94,694**	$97,284
Net income (applicable to common stock)	**$87,578**	$90,168
Earnings per average common share:		
Basic	**$ 1.80**	$ 1.85
Diluted	**$ 1.79**	$ 1.84

As permitted by SFAS No. 123(R), we used the modified prospective method of adopting the new accounting standard; accordingly, financial results for the prior fiscal years presented were not retroactively adjusted to reflect the effects of SFAS No. 123(R). If stock-based compensation expense for the fiscal years ended September 30, 2005 and 2004 had been determined and recorded based on the fair value at the grant dates of the awards consistent with the method prescribed by SFAS No. 123, which was superseded by SFAS No. 123(R), our net income and earnings per share for the years ended September 30, 2005 and 2004 would have been reduced to the amounts shown in the following table.

WGL Holdings, Inc.
Pro Forma Effect of Stock-Based Compensation

	Years Ended September 30,	
(In thousands, except per share data)	2005	2004
Net income as reported	$103,493	$96,637
Add: Stock-based employee compensation expense included in reported net income, net of tax[(a)]	2,205	1,225
Deduct: Total stock-based employee compensation expense determined under the fair value-based method, net of tax[(b)]	(2,733)	(1,656)
Pro forma net income	$102,965	$96,206
Earnings per average common share—basic		
As reported	$ 2.13	$ 1.99
Pro forma	$ 2.11	$ 1.98
Earnings per average common share—diluted		
As reported	$ 2.11	$ 1.98
Pro forma	$ 2.10	$ 1.97

(a) *Reflects compensation expense related to performance shares.*
(b) *Reflects compensation expense related to performance shares and stock options.*

Asset Removal Costs

In March 2005, the FASB issued FIN 47 which clarifies the manner of accounting for AROs containing uncertainties as to the timing and/or method of settlement of the obligation. FIN 47 also clarifies the circumstances under which the fair value of an ARO is considered subject to reasonable estimation. We adopted FIN 47 effective September 30, 2006.

We identified several AROs within the scope of FIN 47. Such AROs include requirements to cut, purge and cap our natural gas pipelines, remove asbestos and plug storage wells upon their retirement. Upon adoption of FIN 47, we recorded an obligation of $27.4 million on the balance sheet to the caption "Asset retirement obligations," which included $23.8 million of accumulated accretion as of September 30, 2006. Additionally, at September 30, 2006 we recorded an addition to "Property, plant and equipment" of $3.5 million associated with AROs, along with accumulated depreciation of $1.0 million. The ARO-related accumulated accretion and depreciation amounts under FIN 47 represent timing differences in the recognition of legal asset removal costs that we are currently recovering in rates and, as such, we have recorded such differences as a reduction to "Regulatory liabilities—Accrued asset removal costs" and as an addition to "Regulatory assets—Other" under SFAS No. 71, in the amount of $24.3 million and $494,000, respectively, as of September 30, 2006.

Had FIN 47 been adopted in the prior fiscal years presented, the ARO as of September 30, 2005 and 2004 would have been $25.8 million and $24.4 million, respectively. In accordance with FIN 47, such prior period amounts are not required to be recorded on the balance sheets.

Inventory

In November 2004, the FASB issued SFAS No. 151, *Inventory Costs*. SFAS No. 151 requires that abnormal amounts of idle facility expense, freight, handling costs and spoilage be charged to income as a current period expense rather than capitalized as inventory costs. SFAS No. 151 became effective for us for inventory costs incurred on and after October 1, 2005. The adoption of this standard had an immaterial effect on our consolidated financial statements for the year ended September 30, 2006.

NEWLY ISSUED ACCOUNTING STANDARDS

Pension and Other Post-Retirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* which amends SFAS No. 87, *Employers' Accounting for Pensions*, SFAS No. 88, *Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits*, SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions* and SFAS 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits.* SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan as an asset or liability on its balance sheet, and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income. SFAS No. 158 will be effective for us on September 30, 2007. Though we are currently evaluating the effect of this new standard, we expect that this new standard will materially affect our balance sheets. We expect that this standard will result in a significant decrease to our "Prepaid qualified pension benefits" and a significant increase to our liability for "Accrued pensions and benefits," along with a corresponding increase to regulatory assets. To the extent regulatory treatment is not granted, amounts recorded to a regulatory asset would be recorded to accumulated other comprehensive loss. Refer to Note 12—*Pensions and Other Post-Retirement Benefit Plans* for disclosures regarding the funded status of our defined benefit post-retirement plans.

Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*, which defines fair value, establishes a framework for measuring fair value in GAAP and expands disclosures about fair value measurements. SFAS No. 157 applies under other accounting pronouncements that require or permit fair value measurements, and does not require any new fair value measurements. SFAS No. 157 is effective for us on October 1, 2008. We are currently evaluating the effect of this new standard on our consolidated financial statements.

Income Taxes

In June 2006, the FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes.* FIN 48 clarifies the accounting for uncertainty in income taxes recognized in financial statements. This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. Additionally, this interpretation provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for us no later than October 1, 2007. We are currently evaluating the effect of this new standard on our consolidated financial statements.

Accounting Changes and Other Matters

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections,* which supersedes APB Opinion No. 20, *Accounting Changes* and SFAS No. 3, *Reporting Accounting Changes in Interim Financial Statements.* SFAS No. 154 changes the requirements for the accounting for and reporting of a change in accounting principle. SFAS No. 154 requires retrospective application to prior period financial statements of changes in accounting principle, unless it is impracticable. SFAS No. 154 was effective for us on October 1, 2006.

In September 2006, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements* (SAB 108), which provides interpretive guidance on how the effects of prior year misstatements should be considered in quantifying a current year misstatement. SAB 108 is effective for us in fiscal year 2007. We are currently evaluating the effect of this new standard on our consolidated financial statements.

2. DISCONTINUED OPERATIONS

During the quarter ended June 30, 2006, we completed a plan for the disposition of ACI and, on September 29, 2006, we sold all of the outstanding shares of common stock of ACI to an unrelated party. ACI was previously reported as part of our commercial HVAC business segment. ACI is reported as a discontinued operation of WGL Holdings and, accordingly, its operating results,

financial position and cash flows have been presented separately from our continuing operations in the consolidated financial statements of WGL Holdings for all fiscal years presented.

For the fiscal years ended September 30, 2006, 2005 and 2004, ACI's net loss from operations of $3.5 million, $2.6 million and $3.0 million, respectively, was presented in "Loss from discontinued operations, net of income tax benefit" on the Consolidated Statements of Income. For the fiscal year ended September 30, 2006, ACI's net loss from operations included a related impairment charge of $578,000, which represents the write-down of ACI's fixed assets to adjust the carrying value of ACI's net assets to its approximate fair value (less estimated costs of sale) as of June 30, 2006. Additionally, "Loss from discontinued operations, net of income tax benefit" for the fiscal year ended September 30, 2006 included a loss of $3.6 million related to the sale of ACI. We did not recognize a tax benefit on either the impairment loss or the loss from the ACI sale because a valuation allowance was established against the deferred tax assets associated with these losses. The following tables summarize selected financial information related to the operating results and financial position of discontinued operations.

Operating Results of Discontinued Operations

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
Revenues[(a)]	**$24,757**	$27,210	$24,561
Loss before income tax benefit (including impairment charge)	**$ (5,053)**	$ (3,722)	$ (4,235)
Loss from sale of ACI	**(3,556)**	–	–
Income tax benefit	**1,493**	1,143	1,277
Loss from discontinued operations, net of income tax benefit	**$ (7,116)**	$ (2,579)	$ (2,958)

[(a)] *Includes intercompany revenues of $1.1 million, $4.3 million and $1.4 million for the years ended September 30, 2006, 2005 and 2004, respectively.*

Assets and Liabilities of Discontinued Operations[(a)]

(In thousands)	September 30, 2005
ASSETS	
Current Assets	
Net receivables	$ 7,172
Other	2,507
Deferred Charges and Other Assets	
Net property, plant and equipment	667
Assets of discontinued operations	$10,346
LIABILITIES	
Current Liabilities	
Accounts payable and other accrued liabilities	$ 2,082
Other	1,128
Deferred Credits	
Deferred income taxes	244
Other	155
Liabilities of discontinued operations	$ 3,609

[(a)] *Due to the September 29, 2006 sale of ACI, there were no assets or liabilities of discontinued operations at September 30, 2006.*

3. SALE OF CARRIED INTEREST

In fiscal year 2004, our non-utility operations realized pre-tax earnings of $6.4 million from the sale, by a third party, of two buildings at Maritime Plaza, a commercial development project in which we held a carried interest. This carried interest had no cost basis, and was accounted for under the equity method. WGL Holdings utilized a capital loss carryforward to offset the federal income taxes associated with this transaction and, after considering other local income tax expense, WGL Holdings realized after-tax earnings

of $5.8 million for the fiscal year ended September 30, 2004. The earnings from this sale were recorded in "Other income (expenses)—net" on the Consolidated Statements of Income for WGL Holdings.

4. ACCOUNTS PAYABLE AND OTHER ACCRUED LIABILITIES

The tables below provide details for the amounts included in "Accounts payable and other accrued liabilities" on the balance sheets for both WGL Holdings and Washington Gas. These amounts do not include accounts payable and other accrued liabilities associated with discontinued operations.

WGL Holdings, Inc.

	At September 30,	
(In thousands)	**2006**	2005
Accounts payable—trade	**$168,144**	$181,429
Employee benefits and payroll accruals	**15,136**	13,806
Other accrued liabilities	**25,221**	8,080
Total	**$208,501**	$203,315

Washington Gas Light Company

	At September 30,	
(In thousands)	**2006**	2005
Accounts payable—trade	**$104,650**	$130,211
Employee benefits and payroll accruals	**13,740**	12,446
Other accrued liabilities	**19,115**	7,049
Total	**$137,505**	$149,706

5. SHORT-TERM DEBT

WGL Holdings and Washington Gas satisfy their short-term financing requirements through the sale of commercial paper or through bank borrowings. Due to the seasonal nature of the regulated utility and retail energy-marketing segments, short-term financing requirements can vary significantly during the year. We maintain revolving credit agreements to support our outstanding commercial paper and to permit short-term borrowing flexibility. Our policy is to maintain bank credit facilities in an amount equal to or greater than our expected maximum commercial paper position.

To support our commercial paper borrowings, WGL Holdings and Washington Gas each have revolving credit agreements with a group of commercial banks that expire on September 30, 2010. The credit facility for WGL Holdings permits it to borrow up to $275 million, and further permits WGL Holdings to request prior to September 30, 2009, and the banks to approve, an additional line of credit of $50 million above the original credit limit, for a maximum potential total of $325 million. The credit facility for Washington Gas permits it to borrow up to $225 million, and further permits Washington Gas to request prior to September 30, 2009, and the banks to approve, an additional line of credit of $100 million above the original credit limit, for a maximum potential total of $325 million. There were no outstanding borrowings under these credit facilities at September 30, 2006 or 2005.

Both WGL Holdings and Washington Gas may reduce the amount of the commitments at their option. Depending on the type of borrowing option chosen under these credit facilities, loans may bear interest at variable rates based on the Eurodollar rate, the higher of the prime lending rate or the Fed Funds effective rate, or at a competitive rate determined through auction.

WGL Holdings and Washington Gas pay facility fees on their credit facilities based on the long-term debt ratings of Washington Gas. In the event the long-term debt of Washington Gas is downgraded below certain levels, WGL Holdings and Washington Gas would be required to pay higher facility fees. Under the terms of the credit facilities, the ratio of consolidated indebtedness to consolidated total capitalization can not exceed 0.65 to 1.0 (65.0 percent). In addition, WGL Holdings and Washington Gas are required to inform lenders of changes in corporate existence, financial conditions, litigation and environmental warranties that might have a material adverse effect. The failure to inform the lenders' agent of changes in these areas deemed material in nature might

constitute default under the agreement. A default, if not remedied, may lead to a suspension of further loans and/or acceleration in which obligations become immediately due and payable.

At September 30, 2006 and 2005, WGL Holdings and its subsidiaries had $177.4 million and $40.9 million, respectively, in commercial paper outstanding at a weighted average cost of 5.36 percent and 3.87 percent, respectively. Included in these consolidated balances were $72.8 million and $10.4 million in commercial paper that Washington Gas had outstanding at September 30, 2006 and 2005, respectively.

6. LONG-TERM DEBT

FIRST MORTGAGE BONDS

The Mortgage of Washington Gas dated January 1, 1933 (Mortgage), as supplemented and amended, securing any First Mortgage Bonds (FMBs) it issues, constitutes a direct lien on substantially all property and franchises owned by Washington Gas, other than a small amount of property that is expressly excluded. Washington Gas had no debt outstanding under the Mortgage at September 30, 2006 and 2005. Any FMBs that may be issued in the future will represent indebtedness of Washington Gas.

SHELF REGISTRATION

At September 30, 2006, Washington Gas had the capacity, under a shelf registration that was declared effective by the SEC on June 8, 2006, to issue up to $300.0 million of MTNs. On June 14, 2006, Washington Gas executed a Distribution Agreement with certain financial institutions for the issuance and sale of debt securities included in the shelf registration statement.

UNSECURED MEDIUM-TERM NOTES

Washington Gas issues unsecured MTNs with individual terms regarding interest rates, maturities and call or put options. These notes can have maturity dates of one or more years from the date of issuance. At September 30, 2006 and 2005, the weighted average interest rate on all outstanding MTNs was 6.15 percent and 6.27 percent, respectively.

The indenture for these unsecured MTNs provides that Washington Gas will not issue any FMBs under its Mortgage without securing all MTNs with all other debt secured by the Mortgage.

Certain of Washington Gas' outstanding MTNs have put options. Certain other MTNs have a make-whole call feature that pays the holder a premium based on a spread over the yield to maturity of a U.S. Treasury security having a comparable maturity, when that particular note is called by Washington Gas before its stated maturity date. With the exception of this make-whole call feature, Washington Gas is not required to pay call premiums for calling debt prior to the stated maturity date.

On June 23, 2006, the Maryland General Assembly enacted legislation which addresses electric industry restructuring issues in Maryland and other issues for all public utilities. Effective July 1, 2007, the legislation requires that all public utilities operating in Maryland, including Washington Gas, obtain approval from the Public Service Commission of Maryland (PSC of MD) before issuing stock, bonds, securities, notes or other debt with a maturity greater than 12 months. We plan to request from the PSC of MD all necessary approvals relating to financing authorizations in order to maintain continuing access to financial markets.

As shown in the table below, during the fiscal years ended September 30, 2006 and 2005, Washington Gas refinanced a total of $75.0 million and $60.5 million of MTNs respectively, with the proceeds from the issuance of lower cost MTNs.

MTN Issuances and Retirements

(In millions)

Date	Principal	Interest Rate	Nominal Maturity Date
Year Ended September 30, 2006			
Issuances:			
01/18/2006	**$25.0**	**5.17%**	**01/18/2016**
01/18/2006	**25.0**	**5.70%**	**01/18/2036**
03/22/2006	**25.0**	**5.78%**	**03/15/2036**
Total	**$75.0**		
Retirements:			
02/15/2006	**$50.0**	**6.15%**	**01/26/2026[a]**
03/22/2006	**25.0**	**7.31%**	**10/30/2007[b]**
Total	**$75.0**		
Year Ended September 30, 2005			
Issuances:			
08/9/2005	$20.0	4.83%	08/09/2015
08/11/2005	40.5	5.44%	08/11/2025
Total	$60.5		
Retirements:			
03/7/2005	$10.0	7.76%	03/06/2025[a]
03/7/2005	10.0	7.75%	03/06/2025[a]
06/9/2005	20.0	6.50%	06/09/2025[a]
06/20/2005	20.5	7.45%	06/20/2005
Total	$60.5		

[a] *Retired through Washington Gas' exercise of call options.*
[b] *In connection with this retirement, Washington Gas paid a make-whole call premium of $958,000 which was recorded as a regulatory asset and is being amortized in accordance with regulatory accounting requirements.*

Refer to Note 7—*Derivative and Weather-Related Instruments* for a discussion of derivative transactions that were settled concurrent with the debt issuances discussed above.

LONG-TERM DEBT MATURITIES

Maturities of long-term debt for each of the next five fiscal years and thereafter as of September 30, 2006 are summarized in the following table.

Long-Term Debt Maturities[a]

(In millions)	MTNs	Other	Total
2007[b]	$ 60.0	$1.0	$ 61.0
2008	20.1	1.1	21.2
2009	75.0	1.1	76.1
2010[b]	32.5	–	32.5
2011	30.0	–	30.0
Thereafter	416.5	–	416.5
Total	634.1	3.2	637.3
Less: current maturities	60.0	1.0	61.0
Total non-current	$574.1	$2.2	$576.3

[a] *Excludes unamortized discounts of $202,000 as of September 30, 2006.*
[b] *Assumes the exercise of a put option by the MTN debt holders of $60.0 million in 2007 and $8.5 million in 2010.*

7. DERIVATIVE AND WEATHER-RELATED INSTRUMENTS

DERIVATIVE INSTRUMENTS

Regulated Utility Operations

Purchase and Sale of Natural Gas. Washington Gas enters into contracts for the sale and purchase of natural gas that qualify as derivative instruments under SFAS No. 133. Washington Gas also enters into other derivative instruments, including swap contracts, related to the sale and purchase of natural gas. As of September 30, 2006 and 2005, such contracts had a net fair value loss of $490,000 and a net fair value gain of $18.2 million, respectively. Of the September 30, 2006 net fair value loss, $14.4 million represented a fair value loss that was recorded on the balance sheet as a payable, with a corresponding $14.0 million recorded as a regulatory asset and $381,000 recorded to expense during fiscal year 2006. This was partially offset by a $13.9 million fair value gain that was recorded as a receivable, with a corresponding $11.6 million recorded as a regulatory liability and $2.3 million recorded to income during fiscal year 2006. Of the September 30, 2005 net fair value gain, $19.9 million represented a fair value gain that was recorded on the balance sheet as a receivable, with a corresponding amount recorded as a regulatory liability. This was partially offset by a $1.7 million fair value loss that was recorded on the balance sheet as a payable, with a corresponding amount recorded as a regulatory asset. This accounting is in accordance with regulatory accounting requirements for recoverable or refundable costs.

Debt Issuances. Washington Gas utilizes derivative instruments that are designed to minimize the risk of interest-rate volatility associated with planned issuances of MTNs. As discussed below, during fiscal years 2006 and 2005, Washington Gas entered into forward-starting swaps that were intended to mitigate a substantial portion of the risk of rising interest rates associated with anticipated future debt issuances. These swaps were carried at fair value.

In February 2006, Washington Gas entered into a forward-starting swap with a notional principal amount of $25.0 million. In conjunction with the issuance of $25.0 million of 5.78 percent MTNs on March 22, 2006, Washington Gas terminated this forward-starting swap and received $303,000 associated with the settlement of this hedge agreement. In July 2005, Washington Gas entered into two forward-starting swaps with an aggregate notional principal amount of $50.0 million. At September 30, 2005, these swaps had a fair value gain totaling $106,000 that was recorded as a receivable, with a corresponding amount recorded as a regulatory liability. In conjunction with the issuance of $25.0 million of 5.17 percent MTNs on January 18, 2006, Washington Gas terminated $25.0 million of the total $50.0 million aggregate notional principal amount of the forward-starting swaps. Washington Gas received $182,000 associated with the settlement of this hedge agreement. Similarly, in conjunction with the issuance of $25.0 million of 5.70 percent MTNs on January 18, 2006, Washington Gas agreed to terminate the remaining $25.0 million notional principal amount of the forward-starting swaps. Washington Gas received $104,000 associated with the settlement of this hedge agreement.

The amounts received upon settlement of these three swaps were recorded as regulatory liabilities, and are being amortized in accordance with regulatory requirements.

In September 2004, Washington Gas entered into two forward-starting swaps with an aggregate notional principal amount of $60.5 million. Concurrent with the issuance of $20.0 million of 4.83 percent MTNs on August 9, 2005, Washington Gas terminated $20.0 million of the total $60.5 million aggregate notional principal amount of the forward-starting swaps. On August 9, 2005, Washington Gas paid $364,000 associated with the settlement of this hedge agreement. Similarly, concurrent with the issuance of $40.5 million of 5.44 percent MTNs on August 11, 2005, Washington Gas agreed to terminate the remaining $40.5 million notional principal amount of the forward-starting swaps. Washington Gas paid $2.2 million associated with the settlement of this hedge agreement. This cost was recorded as a regulatory asset, and is being amortized over the life of the newly issued MTNs in accordance with regulatory accounting requirements.

Refer to Note 6—*Long-Term Debt* for further information on debt issuances.

Non-Utility Operations

Our non-regulated retail energy-marketing subsidiary, WGEServices, enters into contracts for the sale and purchase of natural gas that qualify as derivative instruments under SFAS No. 133. WGEServices also enters into other derivative instruments (primarily in the form of call options, put options and swap contracts) related to the sale and purchase of natural gas. WGEServices' derivative instruments are recorded at fair value on our consolidated balance sheets. Changes in the fair value of these various derivative instruments are reflected in the earnings of our retail energy-marketing segment. At September 30, 2006, these derivative instruments were recorded on our consolidated balance sheets as a net fair value gain of $386,000. This amount was comprised of a $3.3 million fair value gain that was recorded as a receivable, net of a $2.9 million fair value loss that was recorded as a payable. At September 30, 2005, our consolidated balance sheets reflected a fair value gain of $5.4 million related to these derivative instruments that was recorded as a receivable. In connection with these derivative instruments, WGEServices recorded a pre-tax loss of $4.5 million for the fiscal year ended September 30, 2006, and pre-tax gains of $3.8 million and $892,000 for the fiscal years ended September 30, 2005 and 2004, respectively.

Consolidated Operations

The following table summarizes the balance sheet classification for all derivative instruments with open positions for both WGL Holdings and Washington Gas.

Balance Sheet Classification of Open Positions on Derivative Instruments

(In millions)	WGL Holdings		Washington Gas	
September 30,	**2006**	2005	**2006**	2005
Assets				
Current assets—accounts receivable	**$ 0.2**	$15.8	**$ 0.2**	$15.8
Other current assets	**13.9**	5.5	**10.6**	0.1
Deferred charges and other assets—other	**3.1**	4.1	**3.1**	4.1
Total assets	**$17.2**	$25.4	**$13.9**	$20.0
Liabilities				
Accounts payable and other accrued liabilities	**$ 7.1**	$ 1.7	**$ 4.2**	$ 1.7
Other current liabilities	**4.8**	–	**4.8**	–
Deferred credits—other	**5.4**	–	**5.4**	–
Total liabilities	**$17.3**	$ 1.7	**$14.4**	$ 1.7

WEATHER-RELATED INSTRUMENTS

Regulated Utility Operations

Washington Gas has a weather insurance policy designed to mitigate the negative financial effects of warmer-than-normal weather in the District of Columbia. This policy has a three-year term that expires on September 30, 2008. From December 18, 2005

through May 31, 2006, Washington Gas had a weather derivative to protect against warmer-than-normal weather for its Virginia operations. Prior to October 1, 2005, Washington Gas maintained a weather insurance policy covering all of its jurisdictions, and was designed to cover 50 percent of the impact of warmer-than-normal weather on its financial results. This policy expired on September 30, 2005.

During the fiscal year ended September 30, 2006, Washington Gas recorded benefits, net of premium and derivative costs, of $4.7 million related to both its weather insurance policy and weather derivative. In June 2006, Washington Gas received a cash benefit of $6.2 million relating to its weather derivative, and in October 2006, Washington Gas received a cash benefit of $1.3 million relating to its insurance policy. Washington Gas recorded premium expense of $4.2 million during both fiscal years ended September 30, 2005 and 2004, related to the weather insurance policy that expired on September 30, 2005.

On October 5, 2006, Washington Gas purchased a new HDD derivative designed to protect against warmer-than-normal weather in Virginia, covering the period October 15, 2006 through April 30, 2007.

Non-Utility Operations

WGEServices utilizes HDD derivatives for managing risks related to its natural gas sales, and also for its program that allows customers to pay a fixed amount for their gas requirements regardless of the amount of gas consumed. These hedges cover a portion of WGEServices' estimated net revenue exposure to variations in HDDs. These contracts pay WGEServices a fixed dollar amount for every HDD over a specified level during the calculation period. For the fiscal year ended September 30, 2006, 2005 and 2004, we recorded, net of premium costs, pre-tax losses of $2.1 million, $246,000 and $114,000 related to these hedges, respectively.

8. COMMON STOCK

COMMON STOCK OUTSTANDING

Shares of common stock outstanding were 48,878,499, 48,704,340 and 48,652,507 at September 30, 2006, 2005 and 2004, respectively.

COMMON STOCK RESERVES

At September 30, 2006, there were 3,450,523 authorized, but unissued, shares of common stock reserved under the following plans.

Common Stock Reserves

Reserved for:	Number of Shares
1999 Incentive compensation plan[(a)]	1,653,246
Dividend reinvestment and common stock purchase plan	1,102,698
Employee savings plans	637,196
Directors' stock compensation plan	57,383
Total common stock reserves	3,450,523

[(a)] *Included are shares that potentially could be issued and that would reduce the 1999 Incentive Compensation Plan shares authorized. These shares include 1,524,417 shares dedicated to incentive stock options issued but not exercised, and 324,763 shares dedicated to performance shares granted but not vested.*

Refer to Note 13—*Stock-Based Compensation* for a discussion regarding our stock-based compensation plans.

9. PREFERRED STOCK

Washington Gas has three series of cumulative preferred stock outstanding, and each series is callable by Washington Gas. All three series have a dividend preference that prevents Washington Gas from declaring and paying common dividends unless preferred dividends have been paid. In addition, all outstanding shares of preferred stock have a preference as to the amounts that would be

distributed in the event of a liquidation or dissolution of Washington Gas. The following table presents this information, as well as call prices for each preferred stock series outstanding.

Preferred Stock

Preferred Series Outstanding	Shares Outstanding	Liquidation Preference Per Share		Call Price Per Share
		Involuntary	Voluntary	
$4.80	150,000	$100	$101	$101
$4.25	70,600	$100	$105	$105
$5.00	60,000	$100	$102	$102

10. EARNINGS PER SHARE

Basic earnings per share (EPS) is computed by dividing net income by the weighted average number of common shares outstanding during the reported period. Diluted EPS assumes the issuance of common shares pursuant to stock-based compensation plans at the beginning of the applicable period (see Note 13—*Stock-Based Compensation*). The following table reflects the computation of our basic and diluted EPS for the fiscal years ended September 30, 2006, 2005 and 2004.

Basic and Diluted EPS

	Years Ended September 30,		
(In thousands, except per share data)	**2006**	2005	2004
Basic earnings per average common share:			
Income from continuing operations	**$94,694**	$106,072	$99,595
Loss from discontinued operations, net of income tax benefit	**(7,116)**	(2,579)	(2,958)
Net income applicable to common stock	**$87,578**	$103,493	$96,637
Average common shares outstanding—basic	**48,773**	48,688	48,640
Basic earnings per average common share:			
Income from continuing operations	**$ 1.94**	$ 2.18	$ 2.05
Loss from discontinued operations	**(0.14)**	(0.05)	(0.06)
Basic earnings per average common share	**$ 1.80**	$ 2.13	$ 1.99
Diluted earnings per average common share:			
Income from continuing operations	**$94,694**	$106,072	$99,595
Loss from discontinued operations, net of income tax benefit	**(7,116)**	(2,579)	(2,958)
Net income applicable to common stock	**$87,578**	$103,493	$96,637
Average common shares outstanding—basic	**48,773**	48,688	48,640
Stock-based compensation plans	**132**	320	207
Total average common shares outstanding—diluted	**48,905**	49,008	48,847
Diluted earnings per average common share:			
Income from continuing operations	**$ 1.94**	$ 2.16	$ 2.04
Loss from discontinued operations	**(0.15)**	(0.05)	(0.06)
Diluted earnings per average common share	**$ 1.79**	$ 2.11	$ 1.98

For the fiscal year ended September 30, 2006, we had weighted average stock options outstanding totaling 363,000 shares that were not included in the calculation of diluted EPS as their effect would be anti-dilutive.

11. INCOME TAXES

We file a consolidated federal income tax return. Our federal income tax returns for all years through September 30, 2002 have been reviewed and closed, or closed without review by the Internal Revenue Service. WGL Holdings and each of its subsidiaries also participate in a tax sharing agreement that establishes the method for allocating tax benefits from losses to various subsidiaries that are utilized on a consolidated federal income tax return. In fiscal year 2006, Washington Gas realized $1.4 million of tax savings from this tax sharing agreement that were reflected as a tax benefit on Washington Gas' Statements of Income. The effect of this allocation of benefits to Washington Gas has no effect on our consolidated financial statements. During fiscal years 2005 and 2004, Washington Gas realized $1.0 million and $5.3 million, respectively, of tax savings as a result of this tax sharing agreement. State income tax returns are filed on a separate company basis in most states where we have operations and/or a requirement to file. For the District of Columbia, we file a consolidated return.

Our valuation allowance increased by $1.1 million during the fiscal year ended September 30, 2006, caused primarily by a capital loss on the sale of ACI. During the fiscal year ended September 30, 2004, we recognized tax benefits of $2.0 million from the release of a valuation allowance associated primarily with previously unrecognized capital losses. There were no such tax benefits recognized in fiscal years 2006 and 2005. A valuation allowance of $3.1 million and $2.0 million remained for unused tax benefits of capital losses as of September 30, 2006 and 2005, respectively.

The tables below provide the following for WGL Holdings and Washington Gas: *(i)* the components of income tax expense; *(ii)* a reconciliation between the statutory federal income tax rate and the effective income tax rate and *(iii)* the components of accumulated deferred income tax assets and liabilities at September 30, 2006 and 2005. These amounts do not include income taxes associated with discontinued operations.

WGL Holdings, Inc.
Components of Income Tax Expense

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
INCOME TAX EXPENSE			
Current:			
Federal	**$44,041**	$46,745	$25,845
State	**8,501**	9,239	8,844
Total current	**52,542**	55,984	34,689
Deferred:			
Federal			
Accelerated depreciation	**5,136**	(769)	25,983
Other	**894**	2,171	(616)
State			
Accelerated depreciation	**2,188**	6,142	2,308
Other	**1,449**	130	712
Total deferred	**9,667**	7,674	28,387
Amortization of investment tax credits	**(896)**	(897)	(897)
Total income tax expense	**$61,313**	$62,761	$62,179

WGL Holdings, Inc.
Reconciliation Between the Statutory Federal Income Tax Rate and Effective Tax Rate

	Years Ended September 30,					
(In thousands)	**2006**		2005		2004	
Income taxes at statutory federal income tax rate	**$55,064**	**35.00%**	$59,554	35.00%	$57,083	35.00%
Increases (decreases) in income taxes resulting from:						
Accelerated depreciation less amount deferred	**2,769**	**1.76**	1,954	1.15	1,586	0.97
Amortization of investment tax credits	**(896)**	**(0.57)**	(897)	(0.53)	(897)	(0.55)
Cost of removal	**(318)**	**(0.20)**	(248)	(0.15)	(478)	(0.29)
State income taxes-net of federal benefit	**7,056**	**4.48**	7,546	4.43	6,816	4.18
Change in valuation allowance	**–**	**–**	(36)	(0.02)	(1,960)	(1.20)
Medicare D subsidy	**(1,842)**	**(1.17)**	(1,922)	(1.13)	(925)	(0.57)
Other items-net	**(520)**	**(0.33)**	(3,190)	(1.86)	954	0.58
Total income tax expense and effective tax rate	**$61,313**	**38.97%**	$62,761	36.89%	$62,179	38.12%

WGL Holdings, Inc.
Components of Deferred Income Tax Assets (Liabilities)

	At September 30,			
(In thousands)	**2006**		2005	
ACCUMULATED DEFERRED INCOME TAXES	**Current**	**Non-current**	Current	Non-current
Deferred Income Tax Assets:				
Employee benefit costs	**$ 5,542**	**$ –**	$ 5,142	$ –
Uncollectible accounts	**7,279**	**–**	7,034	–
Inventory overheads	**3,873**	**–**	3,599	–
Capital gains/losses-net	**3,106**	**–**	2,005	–
Valuation allowance	**(3,106)**	**–**	(2,005)	–
Compensation & benefits	**–**	**15,087**	–	11,776
Customer advances	**–**	**4,311**	–	3,751
Other	**330**	**546**	792	2,078
Total assets	**17,024**	**19,944**	16,567	17,605
Deferred Income Tax Liabilities:				
Pensions and other employee benefit costs	**–**	**17,317**	–	15,159
Accelerated depreciation and other plant related items	**–**	**267,092**	–	259,828
Losses/gains on reacquired debt	**–**	**3,064**	–	2,784
Income taxes recoverable through future rates	**–**	**23,812**	–	27,093
Deferred gas costs	**5,664**	**3,692**	2,789	3,033
Least-cost planning costs	**–**	**685**	–	1,668
Other	**–**	**–**	–	313
Total liabilities	**5,664**	**315,662**	2,789	309,878
Net accumulated deferred income tax assets (liabilities)	**$11,360**	**$(295,718)**	$13,778	$(292,273)

Washington Gas Light Company
Components of Income Tax Expense

	Years Ended September 30,		
(In thousands)	**2006**	2005	2004
INCOME TAX EXPENSE			
Current:			
Federal	**$35,458**	$38,205	$16,322
State	**5,042**	7,317	7,750
Total current	**40,500**	45,522	24,072
Deferred:			
Federal			
Accelerated depreciation	**5,069**	(689)	25,985
Other	**4,689**	(2,132)	1,644
State			
Accelerated depreciation	**2,188**	6,142	2,308
Other	**349**	(557)	427
Total deferred	**12,295**	2,764	30,364
Amortization of investment tax credits	**(893)**	(893)	(892)
Total income tax expense	**$51,902**	$47,393	$53,544

Washington Gas Light Company
Reconciliation Between the Statutory Federal Income Tax Rate and Effective Tax Rate

	Years Ended September 30,					
(In thousands)	**2006**		2005		2004	
Income taxes at statutory federal income tax rate	**$48,210**	**35.00%**	$47,812	35.00%	$52,547	35.00%
Increases (decreases) in income taxes resulting from:						
Accelerated depreciation less amount deferred	**2,769**	**2.01**	1,954	1.43	1,586	1.06
Amortization of investment tax credits	**(893)**	**(0.65)**	(893)	(0.65)	(892)	(0.59)
Cost of removal	**(318)**	**(0.23)**	(248)	(0.18)	(478)	(0.32)
State income taxes-net of federal benefit	**5,872**	**4.26**	5,827	4.27	6,138	4.09
Consolidated tax sharing allocation	**(1,350)**	**(0.98)**	(1,004)	(0.74)	(5,261)	(3.50)
Medicare D subsidy	**(1,827)**	**(1.33)**	(1,909)	(1.40)	(925)	(0.62)
Other items-net	**(561)**	**(0.40)**	(4,146)	(3.04)	829	0.54
Total income tax expense and effective tax rate	**$51,902**	**37.68%**	$47,393	34.69%	$53,544	35.66%

Washington Gas Light Company
Components of Deferred Income Tax Assets (Liabilities)

	At September 30,			
(In thousands)	**2006**		2005	
ACCUMULATED DEFERRED INCOME TAXES	**Current**	**Non-current**	Current	Non-current
Deferred Income Tax Assets:				
Employee benefit costs	**$ 5,481**	**$ –**	$ 5,123	$ –
Uncollectible accounts	**6,834**	**–**	6,231	–
Inventory overheads	**3,873**	**–**	3,599	–
Compensation & benefits	**–**	**14,961**	–	11,709
Customer advances	**–**	**4,311**	–	3,751
Other	**789**	**–**	793	3,769
Total assets	**16,977**	**19,272**	15,746	19,229
Deferred Income Tax Liabilities:				
Pensions and other employee benefit costs	**–**	**17,237**	–	15,056
Accelerated depreciation and other plant related items	**–**	**267,201**	–	259,944
Losses/gains on reacquired debt	**–**	**3,064**	–	2,784
Income taxes recoverable through future rates	**–**	**23,839**	–	27,093
Deferred gas costs	**5,664**	**3,692**	2,789	3,034
Least-cost planning costs	**–**	**685**	–	1,668
Other	**–**	**767**	–	25
Total liabilities	**5,664**	**316,485**	2,789	309,604
Net accumulated deferred income tax assets (liabilities)	**$11,313**	**$(297,213)**	$12,957	$(290,375)

12. PENSION AND OTHER POST-RETIREMENT BENEFIT PLANS

Washington Gas maintains a qualified, trusteed, non-contributory defined benefit pension plan (qualified pension plan) covering all active and vested former employees of Washington Gas. Executive officers of Washington Gas also participate in a non-funded supplemental executive retirement plan (SERP), a non-qualified defined benefit pension plan. A rabbi trust has been established for the potential future funding of the SERP liability.

Washington Gas provides certain healthcare and life insurance benefits for retired employees. Substantially all employees of Washington Gas may become eligible for such benefits if they attain retirement status while working for Washington Gas. Washington Gas accounts for these benefits under the provisions of SFAS No. 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions.* Washington Gas elected to amortize the accumulated post-retirement benefit obligation of $190.6 million existing at the October 1, 1993 adoption date of this standard, known as the transition obligation, over a twenty-year period. In September 2005, Washington Gas announced changes to post-retirement medical benefits that reduced post-retirement benefit obligations by $34.3 million as of September 30, 2005. These changes will be effective January 1, 2007.

Certain of our subsidiaries offer defined-contribution savings plans to all eligible employees. These plans allow participants to defer on a pre-tax or after-tax basis, a portion of their salaries for investment in various alternatives. We make matching contributions to the amounts contributed by employees in accordance with the specific plan provisions. These contributions to the plans were $3.3 million, $3.1 million and $3.0 million during fiscal years 2006, 2005 and 2004, respectively.

Washington Gas uses a measurement date of September 30 for its pension, and retiree healthcare and life insurance benefit plans. The following table provides certain information about Washington Gas' post-retirement benefits.

Post-Retirement Benefits

(In millions)	Pension Benefits		Health and Life Benefits	
Years Ended September 30,	**2006**	2005	**2006**	2005
Change in benefit obligation				
Benefit obligation at beginning of year	**$691.2**	$655.8	**$ 404.8**	$ 408.5
Service cost	**10.5**	10.2	**10.2**	10.4
Interest cost	**37.2**	36.8	**21.8**	23.0
Change in plan benefits	**0.8**	–	–	(34.3)
Acturarial (gain)/loss	**(4.7)**	24.6	**33.1**	15.9
Benefits paid	**(37.6)**	(36.2)	**(21.5)**	(18.7)
Benefit obligation at end of year	**$697.4**	$691.2	**$ 448.4**	$ 404.8
Change in plan assets				
Fair value of plan assets at beginning of year	**$691.7**	$683.1	**$ 197.4**	$ 175.1
Actual return on plan assets	**46.9**	46.1	**14.6**	8.0
Company contributions	**1.2**	1.2	**29.8**	33.0
Expenses	**(2.4)**	(2.5)	**–**	–
Benefits paid	**(37.5)**	(36.2)	**(21.5)**	(18.7)
Fair value of plan assets at end of year	**$699.9**	$691.7	**$ 220.3**	$ 197.4
Funded status				
Funded status of plan	**$ 2.5**	$ 0.5	**$(228.1)**	$(207.4)
Unrecognized actuarial net loss	**42.8**	44.8	**201.7**	179.3
Unrecognized prior service cost	**11.9**	13.3	**–**	–
Unrecognized transition obligation	**–**	–	**10.1**	11.6
Prepaid (accrued) benefit cost	**$ 57.2**	$ 58.6	**$ (16.3)**	$ (16.5)
Total amounts recognized on balance sheet[(a)]				
Prepaid benefit cost	**$ 76.2**	$ 76.0	**$ –**	$ –
Accrued benefit liability	**(26.6)**	(23.3)	**(16.3)**	(16.5)
Accumulated other comprehensive loss	**7.6**	5.9	**–**	–
Total recognized	**$ 57.2**	$ 58.6	**$ (16.3)**	$ (16.5)

(a) *Excludes regulatory assets and liabilities.*

The Accumulated Benefit Obligation (ABO) for the qualified pension plan was $611.5 million and $609.1 million at September 30, 2006 and 2005, respectively. The projected benefit obligation and ABO for the non-funded SERP, which had accumulated benefits in excess of plan assets, were $29.0 million and $26.6 million, respectively, as of September 30, 2006, and $26.7 million and $23.3 million, respectively, as of September 30, 2005. The SERP is reflected in the table above and has no assets.

At September 30, 2006, Washington Gas had recorded an additional minimum pension obligation of $7.6 million related to the SERP, with a corresponding amount recorded to "Accumulated other comprehensive loss-net of tax." At September 30, 2005, Washington Gas had recorded an additional minimum pension obligation of $5.9 million related to the SERP.

The pre-tax amounts included in other comprehensive loss due to the increase in the minimum pension obligation related to the SERP were $1.7 million ($856,000 after income taxes), and $3.5 million ($2.3 million after income taxes) for the fiscal years ended September 30, 2006 and 2005, respectively.

Assets under the post-retirement benefit plans are valued using a method designed to spread realized and unrealized gains and losses over a period of five years. Each year, 20 percent of the prior five years' asset gains and losses are recognized. The market-related

value of assets is set equal to the market value of assets less the following percentages of prior years' realized and unrealized gains and losses on equities: 80 percent of the prior year, 60 percent of the second prior year, 40 percent of the third prior year and 20 percent of the fourth prior year.

Washington Gas employs a total return investment approach whereby a mix of equities, fixed income and other investments can be used to maximize the long-term return of plan assets for a prudent level of risk. The intent of this strategy is to minimize plan expenses through asset growth over the long run. Risk tolerance is established through consideration of plan liabilities, plan funded status, and corporate financial condition. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset/liability studies, and quarterly investment portfolio reviews.

The asset allocations for the qualified pension plan and healthcare and life insurance benefit trusts as of September 30, 2006 and 2005, and the weighted average target asset allocations as of September 30, 2006, by asset category, are as follows:

Post-Retirement Investment Allocations

	Pension Benefits			Health and Life Benefits		
	Target Allocation	Actual Allocation		Target Allocation	Actual Allocation	
At September 30,	**2006**	**2006**	2005	**2006**	**2006**	2005
Asset Category						
Equity[(a)]	**60%**	**53%**	50%	**50%**	**49%**	50%
Debt	**35%**	**47%**	50%	**50%**	**51%**	50%
Real Estate	**5%**	–	–	–	–	–
Total	**100%**	**100%**	100%	**100%**	**100%**	100%

[(a)] *None of WGL Holdings' common stock is included in these plans.*

Expected benefit payments, including benefits attributable to estimated future employee service, which are expected to be paid over the next ten years are as follows:

Expected Benefit Payments

(In millions)	Pension Benefits	Health and Life Benefits
2007	$ 38.8	$ 20.0
2008	39.8	21.4
2009	40.8	22.9
2010	42.1	24.4
2011	43.6	25.8
2012–2016	243.8	152.9

During fiscal year 2007, Washington Gas does not expect to make any contributions related to its qualified pension plan. On August 17, 2006, the Pension Protection Act of 2006 (the Act) was signed into law. The Act, among other things, sets new funding requirements and new deduction limits for defined benefit pension plans. The new requirements will be phased in over time. The impact of this new legislation will be determined in the future based on how certain provisions are implemented through regulations and guidelines.

Washington Gas expects to make payments totaling $1.3 million in fiscal year 2007 to participants in its non-funded SERP. Washington Gas expects to contribute $32.7 million to its health and life insurance benefit plan during fiscal year 2007.

Components of Net Periodic Benefit Costs (Income)

(In millions)	Pension Benefits			Health and Life Benefits		
Years Ended September 30,	**2006**	2005	2004	**2006**	2005	2004
Components of net periodic benefit costs (income)						
Service cost	**$ 10.5**	$ 10.2	$ 10.3	**$ 10.2**	$ 10.4	$ 8.6
Interest cost	**37.2**	36.8	36.1	**21.8**	23.0	19.8
Expected return on plan assets	**(50.6)**	(51.8)	(52.3)	**(14.3)**	(13.2)	(12.1)
Recognized prior service cost	**2.3**	2.2	2.3	**–**	–	–
Recognized actuarial loss	**3.3**	1.2	1.0	**10.3**	8.9	4.1
Amortization of transition obligation	**–**	–	0.2	**1.5**	5.7	5.7
Net periodic benefit cost (income)	**2.7**	(1.4)	(2.4)	**29.5**	34.8	26.1
Amount allocated to construction projects	**–**	0.3	0.7	**(3.8)**	(3.9)	(4.7)
Amount deferred as regulatory asset (liability)–net	**(4.1)**	(3.4)	(2.7)	**(0.7)**	(1.8)	0.2
Amount charged (credited) to expense	**$ (1.4)**	$ (4.5)	$ (4.4)	**$ 25.0**	$ 29.1	$ 21.6

As a sponsor of a retiree health care benefit plan that is at least actuarially equivalent to Medicare (Medicare Part D), Washington Gas is eligible to receive a federal subsidy under the Medicare Prescription Drug, Improvement and Modernization Act of 2003. During the fiscal year ended September 30, 2006 Washington Gas received $236,000 attributable to the Medicare subsidy. This receipt was included as part of Washington Gas' contribution to its retiree healthcare plan. Expected receipts attributable to the Medicare subsidy to be received over the next ten years are as follows:

Medicare Subsidy Receipts

(In millions)	Health and Life Benefits
2007	$ 1.3
2008	1.4
2009	1.6
2010	1.7
2011	1.8
2012–2016	11.9

The weighted average assumptions used to determine net periodic benefit obligations and net periodic benefit costs were as follows:

Net Periodic Benefit Obligations Assumptions

	Pension Benefits		Health and Life Benefits	
Years Ended September 30,	**2006**	2005	**2006**	2005
Discount rate	**5.75%**	5.50%	**5.75%**	5.50%
Rate of compensation increase	**4.00%**	4.00%	**4.00%**	4.00%

Net Periodic Benefit Cost Assumptions

	Pension Benefits			Health and Life Benefits		
Years Ended September 30,	**2006**	2005	2004	**2006**	2005	2004
Discount rate	**5.50%**	5.75%	6.00%	**5.50%**	5.75%	6.00%
Expected long-term return on plan assets	**8.25%**	8.25%	8.25%	**7.25%**	7.25%	7.25%
Rate of compensation increase	**4.00%**	4.00%	4.00%	**4.00%**	4.00%	4.00%

Washington Gas determines the expected long-term rate of return by averaging the expected earnings for the target asset portfolio. In developing the expected rate of return assumption, Washington Gas evaluates an analysis of historical actual performance and long-term return projections, which gives consideration to our asset mix and anticipated length of obligation of our plan.

Washington Gas assumed the healthcare cost trend rates related to the APBO for Medicare and non-Medicare eligible retirees to be 10.96 percent and 9.25 percent, respectively, for both fiscal years 2006 and 2005. Washington Gas expects these rates to decrease gradually to 5.75 percent and 5.50 percent, respectively, in 2011 and remain at those levels thereafter.

The assumed healthcare trend rate has a significant effect on the amounts reported for the healthcare plans. A one percentage-point change in the assumed healthcare trend rate would have the following effects:

Healthcare Trends

(In millions)	One Percentage-Point Increase	One Percentage-Point Decrease
Increase (decrease) total service and interest cost components	$ 6.1	$ (4.8)
Increase (decrease) post-retirement benefit obligation	$66.5	$(54.4)

In addition to the assumptions listed above, the measurement of net periodic benefit obligations and net periodic benefit costs are dependent on other factors such as mortality rates. Effective September 30, 2006, Washington Gas updated the mortality table it uses to develop its mortality rates to reflect more current life expectancy experience. This change did not have a significant effect on the net periodic benefit obligation of either the pension or the healthcare and life insurance benefit plans.

A significant portion of the estimated post-retirement medical and life insurance benefits apply to our regulated activities.

The Public Service Commission of the District of Columbia (PSC of DC) granted the recovery of post-retirement medical and life insurance benefit costs determined in accordance with GAAP through a five-year phase-in plan that ended September 30, 1998. Washington Gas deferred the difference generated during the phase-in period as a regulatory asset. Effective October 1, 1998, the PSC of DC granted Washington Gas full recovery of costs determined under GAAP, plus a fifteen-year amortization of the regulatory asset established during the phase-in period.

On September 28, 1995, the State Corporation Commission of Virginia (SCC of VA) issued a generic order that allowed Washington Gas to recover most costs determined under GAAP in rates over twenty years. The SCC of VA, however, set a forty-year recovery period of the transition obligation. As prescribed by GAAP, Washington Gas amortizes these costs over a twenty-year period.

The PSC of MD has not rendered a decision that specifically addresses recovery of post-retirement medical and life insurance benefit costs determined in accordance with GAAP. However, the PSC of MD has approved a level of rates sufficient to recover the costs determined under GAAP.

Post-retirement medical and life insurance benefit costs deferred as a regulatory asset at September 30, 2006 and 2005 were $9.3 million and $8.2 million, respectively.

Each regulatory commission having jurisdiction over Washington Gas requires it to fund amounts reflected in rates for post-retirement medical and life insurance benefits into irrevocable trusts. The expected pre-tax long-term rate of return on the assets in the trusts was 7.25 percent for fiscal years 2006, 2005 and 2004. Washington Gas assumes a 35.0 percent federal income tax rate to compute taxes on the taxable portion of the income in the trusts.

13. STOCK-BASED COMPENSATION

STOCK-BASED COMPENSATION FOR KEY EMPLOYEES

We have granted share-based awards in the form of stock options and performance shares under our shareholder-approved 1999 Incentive Compensation Plan, as amended and restated (1999 Plan). The 1999 Plan allows us to issue up to 2,000,000 shares of common stock to persons designated by the Human Resources Committee of the Board of Directors, including officers and key employees. For performance shares, we impose performance goals based on certain market conditions, which if unattained, may result in no performance shares being earned for the applicable performance period. Performance shares granted under the 1999 Plan generally vest over three years from the date of grant. At the end of the associated vesting period, the number of common shares issued related to performance shares depends upon our achievement of performance goals for total shareholder return relative to a selected peer group of companies. We also have granted stock options under the 1999 Plan at the market value of our common stock on the date of grant. Our stock options generally have a vesting period of three years, and expire ten years from the date of grant.

Both stock option and performance share awards provide for accelerated vesting upon change in control. Additionally, the stock options provide for accelerated vesting upon retirement, death or disability. We generally issue new shares of common stock in order to satisfy stock issuances related to both stock options and performance shares; however, we may, from time to time, repurchase shares of our common stock on the open market in order to satisfy these issuances.

For the year ended September 30, 2006, we recognized total stock-based compensation expense of $4.4 million, along with related income tax benefits of $1.8 million, in accordance with SFAS No. 123(R) which we adopted effective October 1, 2005 (refer to Note 1—*Accounting Policies*). For the years ended September 30, 2005 and 2004, we recognized total stock-based compensation expense of $3.4 million and $1.9 million, respectively, along with related income tax benefits of $1.2 million and $660,000, respectively, in accordance with APB Opinion No. 25.

As of September 30, 2006, there was $4.1 million of total unrecognized compensation expense related to share-based awards granted under the 1999 Plan. Performance shares and stock options comprised $2.9 million and $1.2 million of total unrecognized compensation expense, respectively. The total unrecognized compensation expense is expected to be recognized over a weighted average period of 1.6 years, which comprises 1.7 years and 1.5 years for performance shares and stock options, respectively. During the fiscal years ended September 30, 2006, 2005 and 2004, we paid $1.0 million, $415,000 and $254,000, respectively, for income taxes withheld in connection with the settlement of share-based awards.

Performance Shares

The following table summarizes information regarding performance share activity under the 1999 Plan during the fiscal year ended September 30, 2006.

Performance Share Activity

	Year Ended September 30, 2006	
	Number of Shares[(a)]	Weighted Average Grant-Date Fair Value
Non-vested and outstanding, beginning of year	308,012	$27.87
Granted	108,251	$32.62
Vested	(88,180)	$23.91
Cancelled/forfeited	(3,320)	$31.32
Non-vested and outstanding, end of year	324,763	$30.49

[(a)] *The number of common shares issued related to performance shares may range from zero to 200 percent of the number of shares shown in the table above based on our achievement of performance goals for total shareholder return relative to a selected peer group of companies.*

The total intrinsic value of performance shares vested during the years ended September 30, 2006, 2005 and 2004 was $2.6 million, $1.0 million and $645,000, respectively. Performance shares non-vested and outstanding at September 30, 2006 had a weighted average remaining contractual term of 1.0 years.

We measure compensation expense related to performance shares based on the fair value of these awards at their date of grant. Compensation expense for performance shares is recognized for awards that ultimately vest, and is not adjusted based on the actual achievement of performance goals. We estimate the fair value of performance shares on the date of the grant using a Monte Carlo simulation model based on the following assumptions:

Fair Value Assumptions

Years Ended September 30,	**2006**	2005	2004
Expected stock-price volatility	**17.63%**	21.64%	19.04%
Dividend yield	**4.1%**	4.6%	4.6%
Risk-free interest rate	**4.23%**	1.71%	0.94%
Weighted average fair value of performance shares granted during the year	**$32.62**	$29.62	$29.28

Expected stock-price volatility is based on the daily historical volatility of our common shares for the past three fiscal years. The dividend yield represents our annualized dividend yield on the closing market price of our common stock at the date of grant. The risk-free interest rate is based on the zero-coupon U.S. Treasury bond, with a term equal to the three-year contractual term of the performance shares.

Stock Options

The following table summarizes information regarding stock option activity under the 1999 Plan during the fiscal year ended September 30, 2006.

Stock Option Activity

	Number Of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term (In years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2005	1,293,831	$26.76		
Granted	357,742	$32.13		
Exercised	(116,271)	$24.52		
Cancelled/forfeited	(10,885)	$30.47		
Outstanding at September 30, 2006	1,524,417	$28.17	6.95	$5,114
Exercisable at September 30, 2006	468,406	$25.51	4.51	$2,729

We received $2.9 million, $567,000, and $449,000 related to the exercise of stock options during the years ended September 30, 2006, 2005, and 2004, respectively. The actual tax benefit realized for the fiscal year ended September 30, 2006 was $274,000. No tax benefits were realized for the fiscal years ended September 30, 2005 and 2004.

We measure compensation expense related to stock options based on the fair value of these awards at their date of grant. Compensation expense for stock options is recognized for awards that ultimately vest. We estimate the fair value of stock options on the date of the grant using the Black-Scholes option-pricing model based on the following assumptions:

Fair Value Assumptions

Years Ended September 30,	**2006**	2005	2004
Expected stock-price volatility	**22.07%**	21.64%	19.04%
Dividend yield	**4.1%**	4.6%	4.6%
Risk-free interest rate	**4.26%**	1.71%	0.94%
Expected option term	**6.5 years**	3 years	3 years
Weighted average fair value of stock options granted during the year	**$5.51**	$3.07	$2.26

Expected stock-price volatility is based on the daily historical volatility of our common shares over a period that approximates the expected term of the stock options. The dividend yield represents our annualized dividend yield on the closing market price of our common stock at the date of grant. The risk-free interest rate is based on the zero-coupon U.S. Treasury bond, with a term equal to the expected term of the stock options. The expected option term is based on our historical experience with respect to stock option exercises and expectations about future exercises.

STOCK GRANTS TO DIRECTORS

Non-employee directors receive a portion of their annual retainer fee in the form of common stock through the Directors' Stock Compensation Plan. Up to 120,000 shares of common stock may be awarded under the plan. Shares granted to directors totaled 8,400 in both fiscal years 2006 and 2005, and 8,000 for fiscal year 2004. For those years, the fair value of the stock on the grant dates was $30.55, $30.42 and $28.02, respectively. Shares awarded to the participants: *(i)* vest immediately and cannot be forfeited; *(ii)* may be sold or transferred and *(iii)* have voting and dividend rights.

14. ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations related to environmental matters. These evolving laws and regulations may require expenditures over a long timeframe to control environmental effects. Almost all of the environmental liabilities we have recorded are for costs expected to be incurred to remediate sites where we or a predecessor affiliate operated manufactured gas plants (MGP). Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited, to the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete or experience with existing technology that proves ineffective;
- the level of remediation required and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

Washington Gas has identified up to ten sites where it or its predecessors may have operated MGPs. Washington Gas last used any such plant in 1984. In connection with these operations, we are aware that coal tar and certain other by-products of the gas manufacturing process are present at or near some former sites, and may be present at others. Based on the information available to us, we have concluded that none of the sites are likely to present an unacceptable risk to human health or the environment.

At one of the former MGP sites, studies show the presence of coal tar under the site and an adjoining property. Washington Gas has taken steps to control the movement of contaminants into an adjacent river by installing a water treatment system that removes

and treats contaminated groundwater at the site. Washington Gas received approval from governmental authorities for a comprehensive remediation plan for the majority of the site that will allow commercial development of Washington Gas' property. Washington Gas has entered into an agreement with a national developer for the development of this site in phases. The first two phases have been completed, with Washington Gas retaining a ground lease on each phase. The owner of the affected adjoining property has issued a Record of Decision for that portion of the site, and Washington Gas will negotiate an agreement with the owner to perform the remediation. On September 21, 2006, governmental authorities notified Washington Gas of their desire to have the utility investigate and remediate river sediments in the area directly in front of the former MGP site. There has been no agreement among Washington Gas and governmental authorities as to the type and level of sediment investigation and remediation that should be undertaken for this area of the river; accordingly, we cannot estimate at this time the potential future costs of such investigation and remediation.

At a second former MGP site and on an adjacent parcel of land, Washington Gas developed a "monitoring-only" remediation plan for the site. This remediation plan received approval under a state voluntary closure program.

At the remaining eight sites, either the appropriate remediation is being undertaken, or no remediation should be necessary.

At September 30, 2006 and 2005, Washington Gas had a liability of $7.5 million and $8.0 million, respectively, on an undiscounted basis related to future environmental response costs, which included the estimated costs for the ten MGP sites. These estimates principally include the minimum liabilities associated with a range of environmental response costs expected to be incurred at the sites identified. At September 30, 2006 and 2005, Washington Gas estimated the maximum liability associated with all of its sites to be approximately $14.0 million and $14.5 million, respectively. The estimates were determined by Washington Gas' environmental experts, based on experience in remediating MGP sites and advice from legal counsel and environmental consultants. Variations within the range of estimated liability result primarily from differences in the number of years that will be required to perform environmental response processes at each site and the extent of remediation that may be required.

Regulatory orders issued by the PSC of MD allow Washington Gas to recover the costs associated with the sites applicable to Maryland over periods ranging from five to thirty years. Rate orders issued by the PSC of DC allow Washington Gas a three-year recovery of prudently incurred environmental response costs, and allow Washington Gas to defer additional costs incurred between rate cases. Regulatory orders from the SCC of VA have generally allowed the recovery of prudent environmental remediation costs to the extent they were included in a test year.

At September 30, 2006 and 2005, Washington Gas reported a regulatory asset of $3.0 million and $3.2 million, respectively, for the portion of environmental response costs that are expected to be recoverable in future rates. Washington Gas does not expect that the ultimate impact of these matters will have a material adverse effect on its financial statements.

15. COMMITMENTS AND CONTINGENCIES

OPERATING LEASES

Minimum future rental payments under operating leases over the next five years and thereafter are as follows:

Minimum Payments Under Operating Leases

(In millions)	
2007	$ 4.6
2008	4.5
2009	4.2
2010	3.0
2011	3.0
Thereafter	23.4
Total	$42.7

Rent expense totaled $4.3 million, $4.7 million and $3.8 million in fiscal years ended September 30, 2006, 2005 and 2004, respectively.

REGULATED UTILITY OPERATIONS

Operating Issues in Prince George's County, Maryland

On April 1, 2005, Washington Gas announced that it would address a significant increase in the number of natural gas leaks on its distribution system in a portion of Prince George's County, Maryland. Washington Gas retained an engineering consulting firm to determine the reason for the increase in leaks in the affected area of Prince George's County. Based on the work conducted to date by the consulting firm, there is a combination of three contributing factors to the higher leak rates of seals on couplings. However, the contributing factor that is unique to the affected area is the change in the gas composition resulting from a change in the gas supply arising from the reactivation of the Dominion Cove Point (Dominion or Cove Point) liquefied natural gas (LNG) terminal owned by Dominion Resources, Inc. The Cove Point gas has a lower concentration of heavy hydrocarbons (HHCs) than domestic natural gas. The consultant's report indicated that a characteristic of the rubber material comprising the seals in the couplings is the ability of the seals to both adsorb and desorb HHCs. When seals are exposed to higher levels of HHCs, they swell in size and cause a tighter seal. However, when gas, such as the gas from the Cove Point terminal is introduced and it has a lower level of HHCs, the seals shrink in size and there is a greater propensity for those seals to cause the couplings to leak.

Also considered as potential contributing factors to the higher leak rate for seals of this nature are the age of the couplings and the colder ground temperature during the winter. However, both the age of the couplings and the colder ground temperatures are common to couplings in other areas of Washington Gas' service territory where leak patterns have not been observed like those in the affected area of Prince George's County. Thus, in our opinion, the relevant change that explains the higher incidence of leaks in the affected area of Prince George's County is the composition of the gas resulting from the introduction of gas from the Cove Point LNG terminal.

Given the increase in the number of natural gas leaks experienced in the affected area of Prince George's County, Maryland in fiscal year 2005, Washington Gas announced in that year that it would replace gas service lines and rehabilitate gas mains that contain the applicable mechanical couplings in the affected area of the distribution system in Prince George's County (the rehabilitation project), with a projected date of completion by the end of December 2007. The original estimate of the cost of the rehabilitation project is $144 million. This cost estimate could differ materially from the actual costs incurred for the work associated with this project. As a result of the receipt of an Accounting Order dated June 1, 2005 from the PSC of MD, we are capitalizing all costs of encapsulating certain couplings on mains with respect to this rehabilitation project. This phase represents less than 10 percent of the total estimated cost of the rehabilitation project. However, the receipt of the order from the PSC of MD is not determinative of the ratemaking treatment, and the PSC of MD retains jurisdiction to adopt any ratemaking treatment it deems appropriate.

We consider the cost of the rehabilitation project described above necessary to provide safe and reliable utility service. We anticipate that costs such as these eventually will be recognized in the ratemaking process as reasonable. Washington Gas has not yet requested recovery of the capital expenditures and maintenance costs being incurred. However, we are considering the effect of these capital expenditures on Washington Gas' ability to earn its allowed rate of return in Maryland, and we are evaluating the most appropriate options to enable full and timely recovery of, and return on, the amounts being expended. There can be no assurance at this time that recovery in rates will be allowed or at what point in time such recovery may begin to be reflected in rates. If Washington Gas is unable to recover from customers through the regulatory process all or some of these costs and its authorized rate of return on these costs, this could have a significant adverse effect on our financial condition, results of operations, and cash flows.

We anticipate that additional volumes of gas from the Cove Point terminal may flow through facilities in both the affected area of Prince George's County and in other areas of Washington Gas' distribution system as a result of a June 16, 2006 FERC order approving Dominion's application to expand the capacity and output of the Cove Point terminal. As such, Washington Gas has examined potential approaches that will enable it to protect against the adverse effects of the Cove Point gas. The original $144 million cost estimate of the rehabilitation project previously discussed does not consider any costs that have been incurred to date or that will potentially be incurred associated with implementing any of these actions. Based upon the scientific evidence available to date, Washington Gas constructed the facilities necessary to inject HHCs into the gas stream at the gate station that exclusively receives gas from the Cove Point terminal and serves the affected area of Prince George's County, Maryland where the increase in gas leaks had been observed. This facility became operational in January 2006 at a cost of approximately $3.2 million.

Laboratory tests have shown that the injection of HHCs into the type of gas coming from the Cove Point terminal can be effective in re-swelling the seals in couplings which increases their sealing force and, thus, reduces the propensity for the couplings to leak. Furthermore, since the injection facility became operational in January 2006, Washington Gas has been evaluating the

effectiveness of this HHC injection process on the couplings under field conditions. As of September 30, 2006, testing had concluded that the HHCs being injected at this gate station remain in the gas stream and are carried throughout that portion of the distribution system where Washington Gas intends for them to flow.

Washington Gas has observed a reduction in leak rates since the HHC injection facility became operational in January 2006. Given this observation, coupled with the results of the laboratory tests performed to date that support the effectiveness of the HHC injection process, we plan to modify the scope of work on the rehabilitation project through the 2006-2007 winter heating season and anticipate that the overall scope and original $144 million cost estimate of this project may be modified if the expected results materialize in the coming winter. Washington Gas will continue collecting and analyzing leak data in the affected area of Prince George's County through the 2006-2007 winter heating season and we will continue performing special leak surveys before drawing a definitive conclusion regarding the level of effectiveness of the injection process and the overall scope and cost estimate of the rehabilitation project that ultimately will be incurred. Until such time, Washington Gas will continue its rehabilitation efforts within the affected area in Prince George's County at modified levels and will concurrently continue its gas conditioning solution.

Washington Gas has begun the planning necessary to construct two additional facilities to inject HHCs at gate stations in anticipation that more gas from the Cove Point terminal may begin flowing into the interconnected pipelines in fiscal year 2008 or thereafter and, therefore, into other areas of Washington Gas' distribution system. The estimated cost of each of the additional HHC injection facilities will range from an estimated $3 million to $4 million. Washington Gas expects that the cost of these facilities should be includible in the rate base upon which Washington Gas is allowed to earn an allowed rate of return. The estimated cost of these facilities does not include the cost of the purchase of HHCs. At September 30, 2006, Washington Gas had incurred $2.0 million of HHC purchasing costs, and had deferred $575,000 of these costs on the balance sheet as a regulatory asset to be recovered from customers in the future. Currently, Washington Gas is collecting the cost of HHCs in its Purchased Gas Charge (PGC) provision in the District of Columbia from its sales customers. Washington Gas currently is not collecting the cost allocable to Virginia or Maryland customers associated with the purchase of HHCs. The regulatory bodies having jurisdiction over Washington Gas' rates will determine the ultimate amount that is recoverable from customers for the cost of these HHCs (refer to "*Regulatory Matters*").

Natural Gas Contracts—Minimum Commitments

At September 30, 2006, Washington Gas had service agreements with four pipeline companies that provided direct service for firm transportation and/or storage services. These agreements, which have expiration dates ranging from fiscal years 2007 to 2028, require Washington Gas to pay fixed charges each month. At September 30, 2006, Washington Gas had agreements for other pipeline and peaking services with expiration dates ranging from 2007 to 2027. These agreements were entered into based on current estimates of growth of the Washington Gas system, together with current expectations of the timing and extent of unbundling initiatives in the Washington Gas service territory.

The following table summarizes the minimum contractual payments that Washington Gas will make under its pipeline transportation contracts during the next five fiscal years and thereafter.

Washington Gas Contract Minimums

(In millions)	Pipeline Contracts
2007	$ 139.6
2008	146.0
2009	129.7
2010	123.0
2011	110.0
Thereafter	764.0
Total	$1,412.3

Not included in the table above are short-term minimum commitments of $168.2 million to purchase natural gas in fiscal year 2007, as well as a long-term obligation to purchase fixed quantities of natural gas totaling 109.5 million therms per year in fiscal years 2007 through 2010, and 54.6 million therms in fiscal year 2011. Prices for these quantities will be based on market conditions at the time the natural gas is purchased.

When a customer selects a third-party marketer to provide supply, Washington Gas generally assigns pipeline and storage capacity to unregulated third-party marketers to deliver gas to Washington Gas' city gate. In order to provide the gas commodity to customers who do not select an unregulated third-party marketer, Washington Gas has a commodity acquisition plan to acquire the natural gas supply to serve the customer.

In connection with this energy acquisition plan, Washington Gas utilizes an asset manager to acquire a portion of the necessary supply to serve these customers. Washington Gas' commitment to the asset manager, when implementing its option to purchase gas supply through April 30, 2007, is at a market price that is tied to various public indices for natural gas. The contract commitment is related to customer demand, and there are no minimum bill commitments. Accordingly, there are no commitment amounts included in the table above.

Currently, Washington Gas recovers its cost of gas through the purchased gas cost recovery mechanisms included in its retail rate schedules in each of its jurisdictions. However, the timing and extent of Washington Gas' initiatives or regulatory requirements to separate the purchase and sale of natural gas from the delivery of gas could cause its gas supply commitments to be in excess of its continued sales obligations.

Washington Gas has rate provisions in each of its jurisdictions that would allow it to continue to recover potential excess commitments in rates. Washington Gas also actively manages its supply portfolio to ensure its sales and supply obligations remain balanced. This reduces the likelihood that the contracted supply commitments would exceed supply obligations. However, to the extent Washington Gas were to determine that changes in regulation would cause it to discontinue recovery of these costs in rates, Washington Gas would be required to charge these costs to expense without any corresponding revenue recovery. If this occurred, depending upon the timing of the occurrence, the related impact on our financial position and results of operations would likely be significant.

Regulatory Contingencies

Certain legal and administrative proceedings incidental to our business, including regulatory contingencies, involve WGL Holdings and/or its subsidiaries. In our opinion, we have recorded an adequate provision for probable losses or refunds to customers for regulatory contingencies related to these proceedings in accordance with SFAS No. 5, *Accounting for Contingencies.*

District of Columbia Jurisdiction

On May 1, 2006, Washington Gas filed two tariff applications with the PSC of DC requesting approval of proposed revisions to the balancing charge provisions of its firm and interruptible delivery service tariffs that would permit the utility to recover from its delivery service customers the costs of HHCs that are being injected into Washington Gas' natural gas distribution system. Washington Gas has been recovering the costs of HHCs from sales customers in the District of Columbia through its PGC provision in this jurisdiction. On October 2, 2006, the PSC of DC issued an order rejecting Washington Gas' proposed tariff revisions until the PSC of MD concludes on its evidentiary hearing related to this matter which is scheduled to be held on February 6, 2007 (refer to *"Maryland Jurisdiction"* below). On October 12, 2006, Washington Gas filed a Motion for Clarification requesting that the PSC of DC affirm that Washington Gas can continue collecting HHC costs from sales customers through its PGC provision or to record such HHC costs incurred as a regulatory asset pending a ruling by the PSC of DC on future cost recovery. Pending the PSC of DC's decision on the Motion for Clarification, Washington Gas continues to recover the costs of HHCs from sales customers in the District of Columbia through its PGC provision, and is recording these costs as a regulatory asset.

Maryland Jurisdiction

Accounting Order. On April 28, 2005, Washington Gas filed a request for an Accounting Order with the PSC of MD in connection with the rehabilitation project being performed in a portion of Prince George's County, Maryland to address an increase in natural gas leaks (refer to the section entitled *"Operating Issues in Prince George's County, Maryland"*). In this filing, Washington Gas requested that the PSC of MD issue an Accounting Order to ratify Washington Gas' interpretation of the applicable regulatory guidelines regarding the accounting treatment of a portion of the rehabilitation project. Specifically, Washington Gas interpreted the guidelines to require it to record the estimated $13 million cost to encapsulate couplings on mains in the affected areas of Prince George's County as a capital expenditure. After considering this matter at the June 1, 2005 Administrative Meeting of the PSC of MD, the PSC of MD granted Washington Gas' request for an Accounting Order with the understanding that the accounting

treatment will not be determinative of future ratemaking treatment, and the PSC of MD retains jurisdiction to adopt any ratemaking treatment it deems appropriate.

Interruptible Transportation Service and RNA Mechanism. On August 8, 2005, the PSC of MD approved an unopposed Stipulation and Agreement (Stipulation) that was previously filed with the PSC of MD by Washington Gas and three other participants. The Stipulation resolved outstanding issues from an October 31, 2003 Final Order issued by the PSC of MD regarding the manner in which interruptible transportation service is charged to Maryland customers (refer to the section above entitled *"Regulated Service to Interruptible Customers"* for a discussion of this service). As proposed in the Stipulation, the PSC of MD also approved Washington Gas' implementation of a new RNA billing mechanism. The RNA mechanism is designed to stabilize the level of utility net revenues collected from Maryland customers by eliminating the effect of deviations in customer usage caused by variations in weather from normal levels and other factors such as conservation. The Stipulation also allows for the impact of the RNA mechanism on Washington Gas' risk and rate of return to be evaluated in the next rate case. The RNA became effective on October 1, 2005. Washington Gas' net income for the fiscal year ended September 30, 2006 reflects the effect of the RNA.

Disallowance of Purchased Gas Charges. Washington Gas submitted to a routine review of its gas costs that were billed to customers in Maryland from September 2003 through August 2004. Each year, the PSC of MD reviews the annual gas costs collected from customers to determine if Washington Gas' purchased gas costs are not justified because it failed to support that the charges incurred were based solely on increased costs of natural gas, or it failed to follow competitive and reasonable practices in procuring and purchasing natural gas. On March 14, 2006, a Hearing Examiner of the PSC of MD issued a proposed order approving purchased gas charges of Washington Gas for the twelve-month period ending August 2004, except for $4.6 million of such charges that the Hearing Examiner recommended be disallowed because, in the opinion of the Hearing Examiner, they were not reasonably and prudently incurred. Washington Gas filed a Notice of Appeal on April 12, 2006 and a Memorandum on Appeal on April 21, 2006 with the PSC of MD, asserting that the Hearing Examiner's recommendation is without merit. A reply memorandum was filed on May 11, 2006. After consideration of these issues, we expect the PSC of MD to issue a Final Order. Over the past ten years, Washington Gas has incurred similar purchased gas charges which the PSC of MD has reviewed and approved as being reasonably and prudently incurred and therefore subject to recovery from customers. Among other issues included in the appeal, we reminded the PSC of MD of this prior recovery and requested that similar treatment be granted for this matter. During the fiscal year ended September 30, 2006, Washington Gas accrued a liability of $4.6 million (pre-tax) related to the proposed disallowance of these purchased gas charges. If the PSC of MD rules in Washington Gas' favor, the liability recorded in the 2006 fiscal year for this issue will be reversed.

Recovery of Hexane costs. In March 2006, Washington Gas began recovering the costs of HHCs that are being injected into its natural gas distribution system from Maryland sales customers through its PGC provision in Maryland. On April 28, 2006, Washington Gas filed an application with the PSC of MD requesting approval of proposed revisions to the balancing charge provisions of its firm and interruptible delivery service tariffs that would permit the utility to recover the cost of HHCs from its delivery service customers, as well as from its sales customers. On June 27, 2006, the PSC of MD issued an order that rejected Washington Gas' proposed tariff revisions until an evidentiary hearing is held to further consider matters relating to the efficacy of the HHC injections in addressing existing leaks or in preventing additional leaks on Washington Gas' distribution system (refer to the section entitled *"Operating Issues in Prince George's County, Maryland"*). In addition to ordering an evidentiary hearing, the PSC of MD directed Washington Gas to cease recovering HHC costs being recovered through the PGC provision, and to record costs that will be incurred in the future in a "pending" account for future regulatory disposition following the conclusion of the evidentiary hearing. The PSC of MD also indicated that the disposition of HHC costs collected previously through the PGC provision will be determined in the course of the evidentiary hearing which is scheduled to be held on February 6, 2007.

Virginia Jurisdiction

Annual Earnings Test. On December 18, 2003, the SCC of VA issued a Final Order in response to an application filed by Washington Gas on June 14, 2002 to increase annual revenues in Virginia. In connection with this Final Order, the SCC of VA ordered Washington Gas to reduce its rate base related to net utility plant by $28 million, which is net of accumulated deferred income taxes of $14 million, and to establish an equivalent regulatory asset that Washington Gas has done for regulatory accounting purposes only. This regulatory asset, which is presented within "Accumulated depreciation and amortization" on the balance sheets, represents the difference between the accumulated reserve for depreciation recorded on the books of Washington Gas and a theoretical reserve that was derived by the Staff of the SCC of VA (VA Staff) as part of its review of Washington Gas' depreciation rates, less accumulated deferred income taxes. This regulatory asset is being amortized as a component of depreciation expense over

32 years pursuant to the Final Order. The SCC of VA provided for both a return on, and a return of, this regulatory asset established for regulatory accounting purposes.

In approving the treatment described in the preceding paragraph, the SCC of VA further ordered that an annual "earnings test" be performed to determine if Washington Gas has earned in excess of its allowed rate of return on common equity for its Virginia operations. The current procedure for performing this earnings test does not normalize the actual return on equity for the effect of weather over the applicable twelve-month period. To the extent that Washington Gas earns in excess of its allowed return on equity in any annual earnings test period, Washington Gas is required to increase depreciation expense (after considering the impact of income tax benefits), and increase the accumulated reserve for depreciation for the amount of the actual earnings in excess of the earnings produced by a 10.50 percent allowed return on equity. Under the SCC of VA's requirements for performing earnings tests, if weather is warmer than normal in a particular annual earnings test period, Washington Gas is not allowed to restore any amount of earnings previously eliminated as a result of this earnings test. These annual earnings tests will be performed until the $28 million difference between the accumulated reserve for depreciation recorded on Washington Gas' books and the theoretical reserve derived by the VA Staff, net of accumulated deferred income taxes, is eliminated or the level of the regulatory asset established for regulatory accounting purposes is adjusted as a result of a future depreciation study.

In accordance with a September 27, 2004 SCC of VA-approved stipulation involving Washington Gas and other participants, as discussed below, Washington Gas is required to file with the SCC of VA annual earnings test calculations based on a twelve-month period ended December 31. These annual calculations are being estimated by Washington Gas quarterly, and when appropriate, accounting adjustments are being recorded.

On April 27, 2006, Washington Gas filed an earnings test for the twelve months ended December 31, 2005. Washington Gas' filing, which is subject to review by the applicable parties within the SCC of VA, indicated that it had not earned in excess of its allowed return on equity during the period of the earnings test. Washington Gas filed a general rate case application on September 15, 2006. The earnings test for the twelve-month period ended December 31, 2005 will be reviewed by the VA Staff in connection with its review of the September 15, 2006 rate application.

Expedited Rate Case and Stipulation. On January 27, 2004, Washington Gas filed an expedited rate case with the SCC of VA to increase annual revenues in Virginia by $19.6 million. On February 26, 2004, based upon expedited rate case filing procedures, Washington Gas placed the proposed revenue increase into effect, subject to refund, pending the SCC of VA's final decision in the proceeding.

On September 27, 2004, the SCC of VA issued a Final Order approving a proposed stipulation of six participants in the rate case that included Washington Gas and the VA Staff. The approved stipulation, among other things, included no change in Washington Gas' annual base revenues, and maintained Washington Gas' allowed rate of return on common equity of 10.50 percent and overall rate of return of 8.44 percent that had been previously approved by a December 18, 2003 Final Order. Washington Gas had recorded a provision for rate refunds equal to the full amount of revenues that had been collected subject to refund through the fiscal year ended September 30, 2004. Accordingly, there was no effect on earnings for fiscal year 2004 for the rates initially put into effect in February 2004. As discussed above, the stipulation also requires Washington Gas to file with the SCC of VA annual earnings test calculations based on a twelve-month period ended December 31.

Depreciation Study

Washington Gas commissioned a depreciation expert to help prepare a depreciation rate study based on its property, plant and equipment balances as of December 31, 2005. This study was completed in October 2006 and indicates that Washington Gas' depreciation rates should be reduced due to asset lives being extended beyond previously estimated lives. However, under regulatory requirements, these depreciation rates must be approved before they are placed into effect.

In Maryland and the District of Columbia, regulatory requirements prescribe that whenever depreciation rates are revised, there must be a corresponding revision to customer billing rates. Accordingly, the new depreciation rates in Maryland and the District of Columbia will not be placed into effect until a rate case proposal is approved enabling this change.

In connection with a pending rate case in Virginia, on November 8, 2006, Washington Gas filed with the SCC of VA that portion of the depreciation study related to the Virginia jurisdiction. Approval of the study is expected in early fiscal year 2007. The impact of the lower depreciation expense will lower the interim rates to be collected effective February 13, 2007 under the pending rate case. Accordingly, there will be no net income impact for the combined effect of lower revenues and lower depreciation expense

once those new customer billing rates go into effect. However, the regulatory requirements in Virginia will result in a retroactive accounting adjustment to record lower depreciation for the period from January 1, 2006 through the date on which the depreciation study is approved by the SCC of VA.

NON-UTILITY OPERATIONS

WGEServices enters into contracts to purchase natural gas and electricity designed to match the duration of its sales commitments, and effectively to lock in a margin on estimated sales over the terms of existing sales contracts. As listed below, natural gas purchase commitments, which extend through fiscal year 2010, are based on existing fixed-price purchase contracts using city gate equivalent deliveries, the majority of which are for fixed volumes. Also listed below are electricity purchase commitments which extend through fiscal year 2011, and are based on existing fixed-price purchase commitments, all of which are for fixed volumes.

The following table summarizes the contractual obligations and minimum commitments of WGEServices for both natural gas and electricity for the next five years and thereafter:

WGEServices Contract Minimums

(In millions)	Gas Purchase Commitments[(a)]	Pipeline Contracts	Electric Purchase Commitments	Total
2007	$462.8	$1.9	$206.0	$670.7
2008	115.2	0.5	59.7	175.4
2009	28.0	0.2	14.6	42.8
2010	4.5	0.1	6.9	11.5
2011	–	0.1	2.7	2.8
Thereafter	–	–	–	–
Total	$610.5	$2.8	$289.9	$903.2

[(a)] *Represents fixed price commitments with city gate equivalent deliveries.*

Financial Guarantees

WGL Holdings has guaranteed payments primarily for certain purchases of natural gas and electricity made by WGEServices. At September 30, 2006, these guarantees totaled $327.8 million. Termination of these guarantees is coincident with the satisfaction of all obligations of WGEServices covered by the guarantees. WGL Holdings also issued guarantees totaling $4.0 million at September 30, 2006 that were made on behalf of certain of its non-utility subsidiaries associated with their banking transactions. Of the total guarantees of $331.8 million, $3.0 million, $13.0 million, $60,000 and $600,000 are due to expire on December 31, 2006, June 30, 2007, December 31, 2007 and February 29, 2008, respectively. The remaining guarantees of $315.1 million do not have specific maturity dates. For all of its financial guarantees, WGL Holdings may cancel any or all future obligations imposed by the guarantees upon written notice to the counterparty, but WGL Holdings would continue to be responsible for the obligations that had been created under the guarantees prior to the effective date of the cancellation.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS

The following table presents the carrying amounts and estimated fair values of our financial instruments at September 30, 2006 and 2005. The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties. The carrying amount of current assets and current liabilities approximates fair value because of the short-term maturity of these instruments, and therefore are not shown in the table below.

Fair Value of Financial Instruments

At September 30,	**2006**		2005	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Preferred stock	**$ 28.2**	**$ 28.2**	$ 28.2	$ 28.2
Long-term debt[(a)]	**$576.3**	**$593.4**	$584.2	$626.8

[(a)] *Excludes current maturities and unamortized discounts.*

The carrying amount of preferred stock approximates fair value. The fair value of long-term debt was estimated based on the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for Washington Gas' credit quality and the present value of future cash flows.

17. OPERATING SEGMENT REPORTING

In accordance with SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we identify and report on operating segments under the "management approach." Operating segments comprise revenue-generating components of an enterprise for which we produce separate financial information internally that we regularly use to make operating decisions and assess performance. We report three operating segments: *(i)* regulated utility; *(ii)* retail energy-marketing and *(iii)* commercial HVAC.

With approximately 92 percent of WGL Holdings' consolidated total assets, the regulated utility segment is our core business and comprises Washington Gas and Hampshire. The regulated utility segment, through Washington Gas, provides regulated gas distribution services (including the sale and delivery of natural gas, meter reading, responding to customer inquiries, bill preparation and the construction and maintenance of its natural gas distribution system) to customers primarily in Washington, D.C. and the surrounding metropolitan areas in Maryland and Virginia. In addition to the regulated operations of Washington Gas, the regulated utility segment includes the operations of Hampshire, an underground natural gas storage company that is regulated under a cost of service tariff by the FERC and provides services exclusively to Washington Gas.

Through WGEServices, the retail energy-marketing segment sells natural gas and electricity directly to retail customers, both inside and outside of Washington Gas' traditional service territory, in competition with unregulated gas and electricity marketers. Through WGESystems, the commercial HVAC segment designs, renovates and services mechanical heating, ventilating and air conditioning systems for commercial and governmental customers.

Certain of our activities are not significant enough on a stand-alone basis to warrant treatment as an operating segment, and the activities do not fit into one of the segments contained in our financial statements. For purposes of segment reporting, these activities are aggregated in the category "Other Activities" of our non-utility operations as presented below in the Operating Segment Financial Information.

The same accounting policies applied in preparing our consolidated financial statements, as discussed in Note 1—*Accounting Policies*, also apply to the reported segments. While net income or loss is the primary criterion for measuring a segment's performance, we also evaluate our operating segments based on other relevant factors, such as penetration into their respective markets and return

on invested capital. The following tables present operating segment information for the fiscal years ended September 30, 2006, 2005 and 2004.

Operating Segment Financial Information

(In thousands)	Regulated Utility	Non-Utility Operations: Retail Energy-Marketing	Non-Utility Operations: HVAC	Non-Utility Operations: Other Activities	Discontinued Operations	Eliminations	Consolidated
Year Ended September 30, 2006							
Operating Revenues[a]	**$1,637,491**	**$1,001,596**	**$13,138**	**$ 639**	**$ –**	**$ (14,981)**	**$2,637,883**
Operating Expenses:							
Cost of Energy-Related Sales	**1,031,650**	**960,516**	**11,044**	**–**	**–**	**(14,981)**	**1,988,229**
Operation	**198,044**	**16,944**	**1,736**	**2,875**	**–**	**–**	**219,599**
Maintenance	**38,423**	**–**	**–**	**–**	**–**	**–**	**38,423**
Depreciation and Amortization	**92,712**	**333**	**10**	**–**	**–**	**–**	**93,055**
General Taxes and Other Assessments:							
Revenue Taxes[a]	**55,964**	**1,395**	**–**	**–**	**–**	**–**	**57,359**
Other	**40,726**	**(1,976)**	**49**	**29**	**–**	**–**	**38,828**
Total Operating Expenses	**1,457,519**	**977,212**	**12,839**	**2,904**	**–**	**(14,981)**	**2,435,493**
Operating Income (Loss)	**179,972**	**24,384**	**299**	**(2,265)**	**–**	**–**	**202,390**
Other Income (Expenses)—Net	**1,950**	**3**	**357**	**3,784**	**–**	**(2,853)**	**3,241**
Interest Expense	**44,026**	**3,172**	**–**	**3,959**	**–**	**(2,853)**	**48,304**
Dividends on Washington Gas Preferred Stock	**1,320**	**–**	**–**	**–**	**–**	**–**	**1,320**
Income Taxes	**51,977**	**7,900**	**206**	**1,230**	**–**	**–**	**61,313**
Income (Loss) from Continuing Operations	**84,599**	**13,315**	**450**	**(3,670)**	**–**	**–**	**94,694**
Loss from Discontinued Operations, Net of Tax	**–**	**–**	**–**	**–**	**(7,116)**	**–**	**(7,116)**
Net Income (Loss) Applicable to Common Stock	**$ 84,599**	**$ 13,315**	**$ 450**	**$ (3,670)**	**$(7,116)**	**$ –**	**$ 87,578**
Total Assets	**$2,574,186**	**$ 226,675**	**$12,061**	**$107,089**	**$ –**	**$(128,605)**	**$2,791,406**
Capital Expenditures/Investments[b]	**$ 157,906**	**$ 1,849**	**$ 2**	**$ –**	**$ –**	**$ –**	**$ 159,757**
Year Ended September 30, 2005							
Operating Revenues[a]	$1,402,905	$ 773,046	$ 9,482	$ 1,425	$ –	$ (23,515)	$2,163,343
Operating Expenses:							
Cost of Energy-Related Sales	796,413	705,022	8,500	–	–	(23,515)	1,486,420
Operation	201,633	16,049	2,209	2,740	–	(5)	222,626
Maintenance	39,949	–	–	–	–	–	39,949
Depreciation and Amortization	89,859	254	22	–	–	–	90,135
General Taxes and Other Assessments:							
Revenue Taxes[a]	58,170	12,092	–	–	–	–	70,262
Other	40,478	2,210	57	41	–	–	42,786
Total Operating Expenses	1,226,502	735,627	10,788	2,781	–	(23,520)	1,952,178
Operating Income (Loss)	176,403	37,419	(1,306)	(1,356)	–	5	211,165
Other Income (Expenses)—Net	1,159	12	191	1,499	–	(570)	2,291
Interest Expense	41,600	749	203	1,316	–	(565)	43,303
Dividends on Washington Gas Preferred Stock	1,320	–	–	–	–	–	1,320
Income Tax Expense (Benefit)	47,150	14,388	(4)	1,227	–	–	62,761
Income (Loss) from Continuing Operations	87,492	22,294	(1,314)	(2,400)	–	–	106,072
Loss from Discontinued Operations, Net of Tax	–	–	–	–	(2,579)	–	(2,579)
Net Income (Loss) Applicable to Common Stock	$ 87,492	$ 22,294	$ (1,314)	$ (2,400)	$ (2,579)	$ –	$ 103,493
Total Assets	$2,451,831	$ 154,964	$10,921	$ 38,698	$10,346	$ (65,679)	$2,601,081
Capital Expenditures/Investments[b]	$ 112,036	$ 730	$ 2	$ –	$ –	$ –	$ 112,768

Operating Segment Financial Information

(In thousands)	Regulated Utility	Non-Utility Operations: Retail Energy-Marketing	Non-Utility Operations: HVAC	Non-Utility Operations: Other Activities	Discontinued Operations	Eliminations	Consolidated
Year Ended September 30, 2004							
Operating Revenues[a]	$1,293,675	$789,859	$ 6,963	$ 1,673	$ –	$(25,727)	$2,066,443
Operating Expenses:							
Cost of Energy-Related Sales	694,639	744,021	7,251	–	–	(25,671)	1,420,240
Operation	186,823	20,404	2,980	3,807	–	(56)	213,958
Maintenance	44,178	–	–	–	–	–	44,178
Depreciation and Amortization	91,510	218	21	43	–	–	91,792
General Taxes and Other Assessments:							
Revenue Taxes[a]	50,079	9,231	–	–	–	–	59,310
Other	36,544	2,226	47	29	–	–	38,846
Total Operating Expenses	1,103,773	776,100	10,299	3,879	–	(25,727)	1,868,324
Operating Income (Loss)	189,902	13,759	(3,336)	(2,206)	–	–	198,119
Other Income (Expenses)—Net	2,237	159	98	7,314	–	(700)	9,108
Interest Expense	43,141	714	–	978	–	(700)	44,133
Dividends on Washington Gas Preferred Stock	1,320	–	–	–	–	–	1,320
Income Tax Expense (Benefit)	58,727	4,924	(800)	(672)	–	–	62,179
Income (Loss) from Continuing Operations	88,951	8,280	(2,438)	4,802	–	–	99,595
Loss from Discontinued Operations, Net of Tax	–	–	–	–	(2,958)	–	(2,958)
Net Income (Loss) Applicable to Common Stock	$ 88,951	$ 8,280	$ (2,438)	$ 4,802	$ (2,958)	$ –	$ 96,637
Total Assets	$2,333,114	$152,816	$10,807	$86,347	$11,838	$(88,668)	$2,506,254
Capital Expenditures/Investments[b]	$ 108,328	$ 56	$ 4	$ –	$ –	$ –	$ 108,388

[a] *Operating revenues are reported gross of revenue taxes. Revenue taxes of both the regulated utility and the retail energy-marketing segments include gross receipts taxes. Revenue taxes of the regulated utility segment also include PSC fees, franchise fees and energy taxes.*

[b] *Excludes capital expenditures of discontinued operations totaling $158,000, $244,000 and $154,000 for fiscal years ended September 30, 2006, 2005 and 2004, respectively.*

18. RELATED PARTY TRANSACTIONS

WGL Holdings and its subsidiaries engage in transactions among each other during the ordinary course of business. Intercompany transactions and balances have been eliminated from the consolidated financial statements of WGL Holdings.

Washington Gas provides accounting, treasury, legal and other administrative and general support to affiliates, and has filed consolidated tax returns that include affiliated taxable transactions. The actual costs of these services are billed to the appropriate affiliates and to the extent such billings are not yet paid, they are reflected in "Receivables from associated companies" on Washington Gas' balance sheets. Washington Gas does not recognize revenues or expenses associated with providing these services.

In connection with billing for unregulated third-party marketers and with other miscellaneous billing processes, Washington Gas collects cash on behalf of affiliates and transfers the cash as quickly as reasonably possible. Cash collected by Washington Gas on behalf of its affiliates but not yet transferred is recorded in "Payables to associated companies" on Washington Gas' balance sheets. These transactions recorded by Washington Gas impact the balance sheet only.

At September 30, 2006 and 2005, Washington Gas' balance sheets reflected a receivable from associated companies of $1.1 million and $8.1 million, respectively. At September 30, 2006 and 2005, Washington Gas' balance sheets reflected a payable to associated companies of $17.3 million and $18.6 million, respectively.

Additionally, Washington Gas provides gas balancing services related to storage, injections, withdrawals and deliveries to all energy marketers participating in the sale of natural gas on an unregulated basis through the customer choice programs that operate in its service territory. These balancing services include the sale of natural gas supply commodities related to various peaking arrangements contractually supplied to Washington Gas and then partially allocated and assigned by Washington Gas to the energy marketers, including WGEServices. Washington Gas records revenues for these balancing services pursuant to tariffs approved by the appropriate regulatory bodies. In conjunction with such services and the related sales and purchases of natural gas, Washington Gas

charged WGEServices, an affiliated energy marketer, $15.0 million, $23.5 million and $25.7 million for the fiscal years ended September 30, 2006, 2005 and 2004, respectively. These related party amounts have been eliminated in the consolidated financial statements of WGL Holdings.

WGEServices has recognized an accounts receivable from Washington Gas in the amount of $10.3 million and $2.7 million at September 30, 2006 and 2005, respectively, related to imbalance gas transactions as described in Note 1—*Accounting Policies.* Due to regulatory treatment, these receivables are not eliminated in the consolidated financial statements of WGL Holdings.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of WGL Holdings, Inc.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of WGL Holdings, Inc. and subsidiaries (the "Company") as of September 30, 2006 and 2005, and the related consolidated statements of income, common shareholders' equity, and cash flows for each of the three years in the period ended September 30, 2006. Our audits also included the financial statement schedule listed in the Index at Item 15 under Schedule II. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of WGL Holdings, Inc. and subsidiaries as of September 30, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 123(R) "*Share Based Payment*", effective October 1, 2005 and FASB Interpretation No. 47, "*Accounting for Conditional Asset Retirement Obligations*" as of September 30, 2006. Also as discussed in Note 1, during the year ended September 30, 2006 the Company revised the format of its consolidated statements of income. All prior periods have been revised to be consistent with the 2006 presentation. This revision to the income statement presentation did not impact previously reported net income or net income per share.

As discussed in Note 2, the Company discontinued its operations in American Combustion Industries, Inc. ("ACI"), part of its HVAC Segment, in June 2006 and completed the sale of ACI in September 2006. The loss on sale and results prior to the sale are included in loss from discontinued operations in the accompanying consolidated financial statements.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of September 30, 2006, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated December 14, 2006 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

McLean, Virginia
December 14, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of Washington Gas Light Company

We have audited the accompanying balance sheets and statements of capitalization of Washington Gas Light Company (the "Company") as of September 30, 2006 and 2005, and the related statements of income, common shareholder's equity, and cash flows for each of the three years in the period ended September 30, 2006. Our audits also included the financial statement schedule listed in the Index at Item 15 under Schedule II. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and the financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Washington Gas Light Company as of September 30, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the financial statements, the Company adopted Statement of Financial Accounting Standards No. 123(R) *"Share Based Payment"*, effective October 1, 2005 and FASB Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations"* as of September 30, 2006. Also as discussed in Note 1, during the year ended September 30, 2006, the Company revised the format of its statements of income. All prior periods have been revised to be consistent with the 2006 presentation. This revision to the income statement presentation did not impact previously reported net income.

DELOITTE & TOUCHE LLP

McLean, Virginia
December 14, 2006

SUPPLEMENTARY FINANCIAL INFORMATION (Unaudited)

QUARTERLY FINANCIAL DATA

All adjustments necessary for a fair presentation have been included in the quarterly information provided below. Due to the seasonal nature of our business, we report substantial variations in operations on a quarterly basis.

	Quarter Ended			
(In thousands, except per share data)	December 31	March 31[a]	June 30	September 30[b,c]
Fiscal Year 2006[b]				
Operating revenues	**$902,947**	**$1,064,404**	**$346,921**	**$323,611**
Operating income	**85,473**	**105,172**	**9,546**	**2,199**
Income (loss) from continuing operations	**45,252**	**57,254**	**(584)**	**(7,228)**
Net income (loss) (applicable to common stock)	**44,386**	**56,883**	**(1,824)**	**(11,867)**
Earnings (loss) per average share of common stock:				
Basic:[d]				
Income (loss) from continuing operations	**0.93**	**1.17**	**(0.01)**	**(0.15)**
Net income (loss) (applicable to common stock)	**0.91**	**1.17**	**(0.04)**	**(0.24)**
Diluted:[d]				
Income (loss) from continuing operations	**0.93**	**1.17**	**(0.01)**	**(0.15)**
Net income (loss) (applicable to common stock)	**0.91**	**1.16**	**(0.04)**	**(0.24)**
Fiscal Year 2005[b]				
Operating revenues	$617,238	$ 924,355	$343,265	$278,485
Operating income (loss)	81,121	140,548	(295)	(10,209)
Income (loss) from continuing operations	43,649	80,231	(7,407)	(10,401)
Net income (loss) (applicable to common stock)	43,132	79,946	(8,193)	(11,392)
Earnings (loss) per average share of common stock:				
Basic:[d]				
Income (loss) from continuing operations	0.90	1.65	(0.15)	(0.21)
Net income (loss) (applicable to common stock)	0.89	1.64	(0.17)	(0.23)
Diluted:[d]				
Income (loss) from continuing operations	0.89	1.64	(0.15)	(0.21)
Net income (loss) (applicable to common stock)	0.88	1.63	(0.17)	(0.23)

[a] *Quarter ended March 31, 2006 included a charge of $4.6 million (pre-tax), or $0.06 per share, recorded by our regulated utility segment related to a proposed order from a Hearing Examiner of the PSC of MD that recommends the disallowance of certain natural gas costs incurred by Washington Gas and collected from customers in a prior fiscal year. Quarter ended March 31, 2006 also included income of $3.1 million (pre-tax), or $0.04 per share, related to fees that were previously assessed to our retail energy-marketing segment by the PSC of DC stemming from a favorable court decision resulting from our appeal of these fees.*

[b] *On September 29, 2006, we sold all of the outstanding shares of common stock of ACI, previously reported as part of our commercial HVAC business segment. ACI has been reported as a discontinued operation of WGL Holdings and, accordingly, its operating results have been presented separately from our continuing operations for all 2006 and 2005 periods presented. Quarter ended September 30, 2006 also includes a $3.6 million, or $0.08 per share, after-tax loss that resulted from the sale of ACI.*

[c] *Quarter ended September 30, 2005 included adjustments attributable to prior quarters of fiscal year 2005 and prior fiscal years that improved net income by $1.0 million (after tax), or $0.02 per share. We recognized the effect of the prior period adjustments in the fourth quarter of fiscal year 2005, as the effect of these adjustments, both individually and in the aggregate, was not material to the current or prior fiscal years, or to interim periods.*

[d] *The sum of quarterly per share amounts may not equal annual per share amounts as the quarterly calculations are based on varying numbers of common shares.*

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

Senior management, including the Chairman and Chief Executive Officer and the Vice President and Chief Financial Officer, evaluated the effectiveness of WGL Holdings' and Washington Gas' disclosure controls and procedures as of September 30, 2006. Based on this evaluation process, the Chairman and Chief Executive Officer and the Vice President and Chief Financial Officer have concluded that WGL Holdings' and Washington Gas' disclosure controls and procedures were effective as of September 30, 2006.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of WGL Holdings, Inc. and its consolidated subsidiaries (WGL Holdings) is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. WGL Holdings' internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (GAAP).

Because of the inherent limitations of internal control over financial reporting, including the possibility of human error and the circumvention or overriding of controls, material misstatements may not be prevented or detected on a timely basis. Accordingly, even internal controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Furthermore, projections of any evaluation of the effectiveness to future periods are subject to the risk that such controls may become inadequate due to changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management has assessed the effectiveness of WGL Holdings' internal control over financial reporting as of September 30, 2006 based upon the criteria set forth in a report entitled *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment, management has concluded that WGL Holdings maintained effective internal control over financial reporting as of September 30, 2006.

Management's assessment of the effectiveness of WGL Holdings' internal control over financial reporting as of September 30, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm and auditor of WGL Holdings' consolidated financial statements, as stated in their report which is included herein.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

There have been no changes in the Registrants' internal control over financial reporting during the quarter ended September 30, 2006 that have materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of WGL Holdings, Inc.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that WGL Holdings, Inc. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of September 30, 2006, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of September 30, 2006, is fairly stated, in all material respects, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and the financial statement schedule as of and for the year ended September 30, 2006 of the Company and our report dated December 14, 2006 (which report includes explanatory paragraphs relating to the Company's adoption in fiscal 2006 of Statement of Financial Accounting Standards No. 123(R) *"Share Based Payment"* and FASB Interpretation No. 47, *"Accounting for Conditional Asset Retirement Obligations"*, the Company's revision in the format of its consolidated statements of income, and the discontinued operations presentation of American Combustion Industries, Inc. ("ACI"), part of its HVAC Segment) expressed an unqualified opinion on those financial statements and the financial statement schedule.

DELOITTE & TOUCHE LLP

McLean, Virginia
December 14, 2006

ITEM 9B. OTHER INFORMATION

None.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANTS

Information concerning the Company's Board of Directors and the audit committee financial expert contained in WGL Holdings' definitive *Proxy Statement* and Washington Gas' definitive *Information Statement* for the March 1, 2007 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers is reflected in Part I hereof.

ITEM 11. EXECUTIVE COMPENSATION

Information concerning Executive Compensation contained in WGL Holdings' definitive *Proxy Statement* and Washington Gas' definitive *Information Statement* for the March 1, 2007 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of September 30, 2006 is reflected in Part I hereof.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information captioned *Security Ownership of Management and Certain Beneficial Owners* and the information captioned *Equity Compensation Plan Information* in WGL Holdings' definitive *Proxy Statement* and Washington Gas' definitive *Information Statement* for the March 1, 2007 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned *Fiscal Years 2006 and 2005 Audit Firm Fee Summary* in WGL Holdings' definitive *Proxy Statement* and Washington Gas' definitive *Information Statement* for the March 1, 2007 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

Financial Statement Schedules

(a)(1)

All of the financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8.

(a)(2)

Schedule II should be read in conjunction with the financial statements in this report. Schedules not included herein have been omitted because they are not applicable or the required information is shown in the financial statements or notes thereto.

Schedule/ Exhibit	Description
II	Valuation and Qualifying Accounts and Reserves for the years ended September 30, 2006, 2005 and 2004—WGL Holdings, Inc.
	Valuation and Qualifying Accounts and Reserves for the years ended September 30, 2006, 2005 and 2004—Washington Gas Light Company.
(a)(3)	**Exhibits**
	Exhibits Filed Herewith:
	Articles of Incorporation and Bylaws:
3.1	Bylaws of WGL Holdings, Inc. as amended on February 6, 2006.
3.2	Bylaws of Washington Gas Light Company as amended on September 27, 2006.
	Material Contracts:
10.1	Employment Agreement between Washington Gas Light Company and Mr. Adrian P. Chapman, as defined in Item 402(a)(3) of Regulation S-K, dated November 1, 2000.*
12.1	Computation of Ratio of Earnings to Fixed Charges—WGL Holdings, Inc.
12.2	Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends—WGL Holdings, Inc.
12.3	Computation of Ratio of Earnings to Fixed Charges—Washington Gas Light Company.
12.4	Computation of Ratio of Earnings to Fixed Charges and Preferred Stock Dividends—Washington Gas Light Company.
21	Subsidiaries of WGL Holdings, Inc.
23	Consent of Deloitte & Touche LLP.
24	Power of Attorney
31.1	Certification of James H. DeGraffenreidt, Jr., the Chairman and Chief Executive Officer of WGL Holdings, Inc., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Vincent L. Ammann, Jr., the Vice President and Chief Financial Officer of WGL Holdings, Inc., pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.3	Certification of James H. DeGraffenreidt, Jr., the Chairman and Chief Executive Officer of Washington Gas Light Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.4	Certification of Vincent L. Ammann, Jr., the Vice President and Chief Financial Officer of Washington Gas Light Company, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Certification of James H. DeGraffenreidt, Jr., the Chairman and Chief Executive Officer, and Vincent L. Ammann, Jr., the Vice President and Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Schedule/ Exhibit	Description
(a)(3)	**Exhibits (continued)**
	Exhibits Incorporated by Reference:
2	Plan of Merger between WGL Holdings, Inc. and Washington Gas Light Company, filed on Form S-4 dated February 2, 2000.
3	*Articles of Incorporations & Bylaws:*
	Washington Gas Light Company Charter, filed on Form S-3 dated July 21, 1995. WGL Holdings, Inc. Charter and Bylaws, filed on Form S-4 dated February 2, 2000.
4	*Instruments Defining the Rights of Security Holders including Indentures:*
	Indenture, dated September 1, 1991 between Washington Gas Light Company and The Bank of New York, as Trustee, regarding issuance of unsecured notes, filed as an exhibit to Form 8-K on September 19, 1991.
	Supplemental Indenture, dated September 1, 1993 between Washington Gas Light Company and The Bank of New York, as Trustee, regarding the addition of a new section to the Indenture dated September 1, 1991, filed as an exhibit to Form 8-K on September 10, 1993.
10	*Material Contracts:*
	Gas transportation and storage contracts
	Service Agreement, effective November 1, 2005, with Columbia Gulf Transmission Company related to Firm Transportation Service, filed as Exhibit 10.1 to Form 10-K for the fiscal year ended September 30, 2005.
	Service Agreement, effective November 1, 2005, with Columbia Gas Transmission Corporation related to Firm Storage Service (Agreement 85037), filed as Exhibit 10.2 to Form 10-K for the fiscal year ended September 30, 2005.
	Service Agreement, effective November 1, 2005, with Columbia Gas Transmission Corporation related to Storage Service (Agreement 85038), filed as Exhibit 10.3 to Form 10-K for the fiscal year ended September 30, 2005.
	Service Agreement, effective November 1, 2005, with Columbia Gas Transmission Corporation related to Firm Transportation Service (Agreement 85036), filed as Exhibit 10.4 to Form 10-K for the fiscal year ended September 30, 2005.
	Service Agreement, effective November 1, 2005, with Cove Point LNG FPS—2 related to Peaking Service, filed as Exhibit 10.5 to Form 10-K for the fiscal year ended September 30, 2005.
	Service Agreement, effective November 1, 2005, with Cove Point LNG FPS—3 related to Peaking Service, filed as Exhibit 10.6 to Form 10-K for the fiscal year ended September 30, 2005.
	Service Agreement, effective May 1, 2005, as amended, with Dominion Cove Point LNG, LP related to Firm Transportation Service, filed as Exhibit 10.2 to Form 10-K for the fiscal year ended September 30, 2004.
	Service Agreement, effective November 1, 2004, with Dominion Transmission Inc. related to Firm Transportation Service from the Mid Atlantic project, filed as Exhibit 10.5 to Form 10-K for the fiscal year ended September 30, 2004.
	Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Firm Storage Service, filed as Exhibit 10.7 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78844)
	Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Firm Storage Service, filed as Exhibit 10.7 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78845)

Schedule/ Exhibit	Description
(a)(3)	**Exhibits (continued)**

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Firm Storage Service, filed as Exhibit 10.7 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78846)

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Storage Service filed as Exhibit 10.8 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78838)

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Storage Service filed as Exhibit 10.8 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78839)

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Storage Service filed as Exhibit 10.8 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78840)

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Firm Transportation Service, filed as Exhibit 10.9 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78834)

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Firm Transportation Service, filed as Exhibit 10.9 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78835)

Service Agreement, renegotiated and effective June 1, 2004, as amended, with Columbia Gas Transmission Corporation related to Firm Transportation Service, filed as Exhibit 10.9 to Form 10-K for the fiscal year ended September 30, 2004. (Agreement 78836)

Service Agreement, effective January 1, 1996, with Transcontinental Gas Pipe Line Corporation related to Firm Transportation Service, filed as Exhibit 10.11 to Form 10-K for the fiscal year ended September 30, 2004.

Service Agreement effective November 1, 2002 with the Transcontinental Gas Pipe Line Corporation for the MarketLink Firm Transportation Capacity, filed as Exhibit 10.1 to Form 10-K for the fiscal year ended September 30, 2003.

Service Agreement effective October 1, 1993 with Transcontinental Gas Pine Line Corporation related to General Storage Service filed as Exhibit 10.3 to Form 10-K for the fiscal year ended September 30, 1993.

Service Agreement effective October 1, 1993 with Dominion Transmission, Inc. related to Firm Transportation Service, filed as Exhibit 10.11 to Form 10-K for the fiscal year ended September 30, 1993.

Service Agreement effective October 1, 1993 with Dominion Transmission, Inc. related to General Storage Service, filed as Exhibit 10.13 to Form 10-K for the fiscal year ended September 30, 1993.

Service Agreement effective August 1, 1991 with Transcontinental Gas Pipe Line Corporation related to Washington Storage Service, filed as Exhibit 10.16 to Form 10-K for the fiscal year ended September 30, 1993.

Management Contracts with Executive Officers and Directors

WGL Holdings, Inc. 1999 Incentive Compensation Plan, as amended and restated as of March 5, 2003, filed as Exhibit 10.15 to Form 10-K for the fiscal year ended September 30, 2004.*

Form of Nonqualified Stock Option Award Agreement, filed as Exhibit 10.01 to Form 8-K dated October 5, 2004.*

Form of Performance Share Award Agreement, filed as Exhibit 10.02 to Form 8-K dated October 5, 2004.*

Schedule/ Exhibit	Description
(a)(3)	**Exhibits (continued)**

Employment Agreement between Washington Gas Light Company and Ms. Beverly J. Burke, as defined in Item 402(a)(3) of Regulation S-K, dated December 14, 2001, filed as Exhibit 10.2 to Form 10-K for the fiscal year ended September 30, 2003.*

Employment Agreement between Washington Gas Light Company and Mr. Thomas F. Bonner, as defined in Item 402(a)(3) of Regulation S-K, dated April 29, 2002, filed as Exhibit 10.3 to Form 10-K for the fiscal year ended September 30, 2003.*

Employment Agreement between Washington Gas Light Company and Mr. Terry D. McCallister, as defined in Item 402(a)(3) of Regulation S-K, filed as Exhibit 10.1 to Form 10-K in the fiscal year ended September 30, 2001.*

WGL Holdings, Inc. and Washington Gas Light Company Deferred Compensation Plan for Outside Directors, adopted December 18, 1985, and amended as of November 1, 2000, filed as Exhibit 10.2 to Form 10-K in the fiscal year ended September 30, 2001.*

Employment Agreement between Washington Gas Light Company and Mr. Frederic M. Kline, as defined in Item 402(a)(3) of Regulation S-K, filed as Exhibit 10.5 to Form 10-K in the fiscal year ended September 30, 2001.*

Employment Agreement between Washington Gas Light Company and Mr. James H. DeGraffenreidt, Jr., as defined in Item 402(a)(3) of Regulation S-K, filed as Exhibit 10.7 to Form 10-K in the fiscal year ended September 30, 2001.*

Washington Gas Light Company Supplemental Executive Retirement Plan amended November 1, 2000, filed as Exhibit 10.8 to Form 10-K in the fiscal year ended September 30, 2001.*

WGL Holdings, Inc. Long-Term Incentive Compensation Plan, adopted June 28, 1989, amended as of November 1, 2000, filed as Exhibit 10.9 to Form 10-K in the fiscal year ended September 30, 2001.*

Debt and Credit Agreements

Amended and Restated Credit Agreement dated as of September 30, 2005 among WGL Holdings, Inc., the Lenders, The Bank of New York, as administrative agent; Wachovia Bank, National Association, as syndication agent; Bank of Tokyo-Mitsubishi Trust Company, Citibank, N.A., and SunTrust Bank, as documentation agents; and Wachovia Capital Markets, LLC, as lead arranger and book runner. Filed as Exhibit 10.1 to Form 8-K dated October 6, 2005.

Amended and Restated Credit Agreement dated as of September 30, 2005 among Washington Gas Light Company, the Lenders, The Bank of New York, as administrative agent; Wachovia Bank, National Association, as syndication agent; Bank of Tokyo-Mitsubishi Trust Company, Citibank, N.A., and SunTrust Bank, as documentation agents; and Wachovia Capital Markets, LLC, as lead arranger and book runner. Filed as Exhibit 10.2 to Form 8-K dated October 6, 2005.

Form of Distribution Agreement dated June 14, 2006 among Washington Gas Light Company and Citigroup Global Markets Inc., Banc of America Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, SunTrust Capital Markets, Inc., The Williams Capital Group, L.P. and Wachovia Capital Markets, LLC regarding the issuance and sale by Washington Gas Light Company of up to $300 million of Medium-Term Notes, Series H under an Indenture dated as of September 1, 1991. Filed as Exhibit 1.1 to Form 8-K dated June 15, 2006.

* This asterisk designates an agreement that is a compensatory plan or arrangement.

WGL Holdings, Inc. and Subsidiaries
Schedule II—Valuation and Qualifying Accounts and Reserves
Years Ended September 30, 2006, 2005 and 2004

(In thousands)	*Balance at Beginning of Period*	*Additions Charged To*		*Deductions*[(b)]	*Balance at End of Period*
		Costs and Expenses	*Other Accounts*[(a)]		
2006					
Valuation and Qualifying Accounts Deducted from Assets in the Balance Sheet: Allowance for Doubtful Accounts	**$16,835**	**$16,203**	**$4,548**	**$19,910**	**$17,676**
2005					
Valuation and Qualifying Accounts Deducted from Assets in the Balance Sheet: Allowance for Doubtful Accounts	$15,430	$17,574	$4,464	$20,633	$16,835
2004					
Valuation and Qualifying Accounts Deducted from Assets in the Balance Sheet: Allowance for Doubtful Accounts	$17,223	$12,007	$3,173	$16,973	$15,430

Notes:

(a) *Recoveries on receivables previously written off as uncollectible and unclaimed customer deposits, overpayments, etc., not refundable.*

(b) *Includes deductions for purposes for which reserves were provided or revisions made of estimated exposure.*

Washington Gas Light Company
Schedule II—Valuation and Qualifying Accounts and Reserves
Years Ended September 30, 2006, 2005 and 2004

(In thousands)	*Balance at Beginning of Period*	*Additions Charged To*		*Deductions*[b]	*Balance at End of Period*
		Costs and Expenses	*Other Accounts*[a]		
2006					
Valuation and Qualifying Accounts Deducted from Assets in the Balance Sheet: Allowance for Doubtful Accounts	**$14,981**	**$14,001**	**$4,548**	**$16,987**	**$16,543**
2005					
Valuation and Qualifying Accounts Deducted from Assets in the Balance Sheet: Allowance for Doubtful Accounts	$13,202	$14,625	$4,179	$17,025	$14,981
2004					
Valuation and Qualifying Accounts Deducted from Assets in the Balance Sheet: Allowance for Doubtful Accounts	$15,826	$11,111	$3,173	$16,908	$13,202

Notes:

[a] *Recoveries on receivables previously written off as uncollectible and unclaimed customer deposits, overpayments, etc., not refundable.*

[b] *Includes deductions for purposes for which reserves were provided or revisions made of estimated exposure.*

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized.

WGL HOLDINGS, INC.
and
WASHINGTON GAS LIGHT COMPANY
(Co-registrants)
/s/ Vincent L. Ammann, Jr.
Vincent L. Ammann, Jr.
Vice President and
Chief Financial Officer

Date: December 14, 2006

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ James H. DeGraffenreidt, Jr. (James H. DeGraffenreidt, Jr.)	Chairman of the Board and Chief Executive Officer	December 14, 2006
/s/ Terry D. McCallister (Terry D. McCallister)	President and Chief Operating Officer	December 14, 2006
/s/ Vincent L. Ammann, Jr. (Vincent L. Ammann, Jr.)	Vice President and Chief Financial Officer (Principal Financial Officer)	December 14, 2006
/s/ Mark P. O'Flynn (Mark P. O'Flynn)	Controller (Principal Accounting Officer)	December 14, 2006
* (Michael D. Barnes)	Director	December 14, 2006
* (George P. Clancy, Jr.)	Director	December 14, 2006
* (James W. Dyke, Jr.)	Director	December 14, 2006
* (Melvyn J. Estrin)	Director	December 14, 2006
* (James F. Lafond)	Director	December 14, 2006
* (Debra L. Lee)	Director	December 14, 2006
* (Karen Hastie Williams)	Director	December 14, 2006
*By: Vincent L. Ammann, Jr. **(Vincent L. Ammann, Jr.)** *Attorney-in-Fact*		December 14, 2006

Exhibit 31.1

CERTIFICATION OF WGL HOLDINGS, INC.

I, James H. DeGraffenreidt, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of WGL Holdings, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: December 14, 2006

/s/ James H. DeGraffenreidt, Jr.

James H. DeGraffenreidt, Jr.
Chairman and Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF WGL HOLDINGS, INC.

I, Vincent L. Ammann, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of WGL Holdings, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: December 14, 2006

/s/ Vincent L. Ammann, Jr.

Vincent L. Ammann, Jr.
Vice President and Chief Financial Officer

Exhibit 31.3

CERTIFICATION OF WASHINGTON GAS LIGHT COMPANY

I, James H. DeGraffenreidt, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Washington Gas Light Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: December 14, 2006

/s/ James H. DeGraffenreidt, Jr.

James H. DeGraffenreidt, Jr.
Chairman and Chief Executive Officer

Exhibit 31.4

CERTIFICATION OF WASHINGTON GAS LIGHT COMPANY

I, Vincent L. Ammann, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Washington Gas Light Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:
   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors:
   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: December 14, 2006

/s/ Vincent L. Ammann, Jr.

Vincent L. Ammann, Jr.
Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION OF THE CHAIRMAN AND CHIEF EXECUTIVE OFFICER AND THE VICE PRESIDENT AND CHIEF FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the combined Annual Report of WGL Holdings, Inc. and Washington Gas Light Company (the "Companies") on Form 10-K for the annual period ended September 30, 2006 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), James H. DeGraffenreidt, Jr., Chairman and Chief Executive Officer of the Companies, and Vincent L. Ammann, Jr., Vice President and Chief Financial Officer of the Companies, each hereby certify, pursuant to 18 U.S.C. § 1350, as adopted pursuant to § 906 of the Sarbanes-Oxley Act of 2002, to the best of their knowledge, that:

(1) The Report fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Companies.

This certification is being made for the exclusive purpose of compliance by the Chairman and Chief Executive Officer and the Vice President and Chief Financial Officer of the Companies with the requirements of Section 906 of the Sarbanes-Oxley Act of 2002, and may not be disclosed, distributed, or used by any person for any reason other than as specifically required by law.

/s/ James H. DeGraffenreidt, Jr.

James H. DeGraffenreidt, Jr.
Chairman and Chief Executive Officer

/s/ Vincent L. Ammann, Jr.

Vincent L. Ammann, Jr.
Vice President and Chief Financial Officer

December 14, 2006

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Form 10-K

NORTHWEST NATURAL GAS CO - NWN

Filed: February 28, 2007 (period: December 31, 2006)

Annual report which provides a comprehensive overview of the company for the past year

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SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2006

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from_____ to_____

Commission file number 1-15973

NORTHWEST NATURAL GAS COMPANY

(Exact name of registrant as specified in its charter)

Oregon	**93-0256722**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

220 N.W. Second Avenue, Portland, Oregon 97209

(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(503) 226-4211**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act). Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. [ ]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act 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 [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K [ ]

Indicate by check mark whether the registrant is a large accelerated filer (as defined in Rule 12b-2 of the Act). Yes [X] No [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes [ ]

No [X]

As of June 30, 2006, the registrant had 27,547,346 shares of its Common Stock outstanding. The aggregate market value of these shares of Common Stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by non-affiliates was $1,010,618,119.

Indicate number of shares outstanding of each of registrant's classes of common stock as of February 23, 2007:

Common Stock	27,256,341

DOCUMENTS INCORPORATED BY REFERENCE

List documents incorporated by reference and the Part of the Form 10-K into which the document is incorporated.

Portions of the Proxy Statement of Company, to be filed in connection with the 2007 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY

Annual Report to Securities and Exchange Commission

on Form 10-K

For the Fiscal Year Ended December 31, 2006

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GLOSSARY OF TERMS

Basic earnings per share: earnings applicable to common stock for a period, divided by the average number of shares of common stock outstanding during that period.

Bcf: one billion cubic feet, a volumetric measure of natural gas, roughly equal to 10 million therms.

Btu: British thermal unit, a basic unit of thermal energy measurement. One Btu equals the energy required to raise one pound of water one degree Fahrenheit. One hundred thousand Btu's equal one therm.

Bypass: a direct connection to the interstate gas pipeline, which circumvents the pipes of the local gas distribution company; usually considered only by large industrial users.

Core utility customers: residential, commercial and industrial firm service customers on our distribution system.

Decoupling: a rate mechanism which is designed to break the link between earnings and the quantity of natural gas consumed by customers. The design is intended to allow the utility to encourage customers to conserve energy while not adversely affecting its earnings due to losses in sales volumes.

Degree days: units of measure that reflect temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperature from 65 degrees Fahrenheit.

Demand charge: a component in all core utility gas rates that covers the cost of securing pipeline capacity to meet peak demand, whether that capacity is used or not.

Design day: a design day is the maximum anticipated demand on the natural gas distribution system during a 24-hour period assuming weather at an average temperature of 12 degrees Fahrenheit, the coldest day in the last 20 years in our service territory.

Diluted earnings per share: earnings applicable to common stock for a period, divided by the average number of shares of stock that would be outstanding assuming the issuance of common shares for all existing stock based compensation plans with a dilutive impact during the reporting period.

Firm service: natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers, particularly during cold weather.

Gas storage: a means of holding gas in reserve for future delivery, either through injection into an underground storage field, or storing it in the form of liquefied natural gas.

General rate case: a periodic filing with state regulators to establish equitable rates and balance the interests of all classes of customers and our shareholders.

Interruptible service: natural gas service offered to customers (usually large commercial or industrial) under contracts or rate schedules that allow for temporary interruptions to meet the needs of firm service customers.

Liquefied natural gas (LNG): the cryogenic liquid form of natural gas. At temperatures below minus 258 degrees Fahrenheit, natural gas can be stored in a liquid form, which is 600 times more dense than its gaseous form.

Margin: gross revenues less the associated cost of sales. Also referred to as net operating revenues.

Purchased Gas Adjustment (PGA): also known as the gas cost tracker, is a regulatory mechanism for annually adjusting customer rates due to changes in gas commodity costs.

Return on equity (ROE): a measure of corporate profitability, calculated as net income divided by average common stock equity. Authorized ROE refers to the equity rate approved by a regulatory agency for utility investments funded by common stock equity.

Return on invested capital: a measure of profitability calculated by dividing net income before interest expense by average long-term capital.

Sales service: service provided to a customer that receives both natural gas supply and transportation of that gas from the regulated utility.

Therm: the basic unit of natural gas measurement, equal to 100,000 Btu's. An average residential customer in our service area uses about 700 therms in an average-weather year.

Transportation service: service provided to a customer that secures its own natural gas supply and pays the regulated utility only for use of the distribution system to transport it.

Underground gas storage: storage of natural gas by injection into underground rock formations; historically gas is withdrawn during the winter heating season or during periods of high gas prices.

Utility margin: utility gross revenues less the associated cost of gas and applicable revenue taxes. Also referred to as utility net operating revenues.

Weather normalization: a rate mechanism that allows a utility to adjust customers' bills during the winter heating season to reduce variations in margin recovery due to fluctuations from average temperatures.

Winter heating season: generally considered to be the period from November through March.

NORTHWEST NATURAL GAS COMPANY

PART I

ITEM 1. BUSINESS

General

Northwest Natural Gas Company was incorporated under the laws of Oregon in 1910. Our company and its predecessors have supplied gas service to the public since 1859. Since September 1997, we have been doing business as NW Natural.

Business Segments

Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. In this report our principal business segment is referred to as local gas distribution or utility. Local gas distribution involves purchasing gas from producers, transporting the gas over interstate pipelines from the supply basins to our service territory, and reselling the gas to customers at rates and terms approved by the Oregon Public Utility Commission (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Gas distribution also includes transporting gas owned by large customers from the interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 98 percent of our consolidated assets are related to the local gas distribution segment. The OPUC has allocated to us as our exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley and the coastal area from Astoria to Coos Bay. We also hold certificates from the WUTC granting us exclusive rights to serve portions of three southern Washington counties bordering the Columbia River. Gas service is provided in 122 cities and neighboring communities, in 15 Oregon counties, as well as in 14 cities and neighboring communities in three Washington counties. The city of Portland is the principal retail and manufacturing center in the Columbia River Basin, and is a major port for trade with Asia.

At year-end 2006, we had 575,116 residential customers, 60,523 commercial customers and 945 industrial sales customers. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. Industries served include: pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry accounts for a significant portion of our industrial revenues.

Gas Storage

The gas storage business segment (previously referred to as Interstate Gas Storage) includes NW Natural's underground natural gas storage services to rge intrastate and interstate customers using NW Natural's storage and related transportation capacity that is in excess of the utility's core (residential, commercial and ..idustrial firm) customer requirements. Additionally, an independent energy marketing company provides asset optimization services to the utility under a contractual arrangement. Approximately 2 percent of our consolidated assets and 9 percent of consolidated net

income in 2006 are related to the gas storage business segment. For each of the years ended December 31, 2006, 2005 and 2004, this business segment derived a majority of its revenues from five storage customers. The largest of these customers is served under a long-term contract. The total working gas capacity of the Mist derground gas storage facility has been revised from 13.9 Bcf to around 14 Bcf to reflect reservoir performance and incremental growth in certain reservoir pools. Of his capacity, the gas storage business included in this segment has access to about 5 Bcf of capacity while the core utility has access to the remaining 9 Bcf.

Pre-tax income from gas storage and third-party optimization is subject to revenue sharing with core utility customers. In Oregon, 80 percent of the pre-tax income is retained by this segment when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income is retained when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent of pre-tax income, respectively, are deferred to a regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage services and third-party optimization.

Interstate Gas Storage. This part of the business segment provides firm and interruptible gas storage and related transportation services on NW Natural's system to several interstate customers. The interstate storage services and maximum rates are authorized by the Federal Energy Regulatory Commission (FERC). The storage capacity used by this business has been developed by NW Natural in advance of core utility customers' requirements.

Intrastate Gas Storage. In February 2006, we began providing an Oregon firm intrastate gas storage service under an OPUC-approved rate schedule. The firm storage service terms and conditions mirror the firm interstate storage service, except that these customers are located and served in Oregon under an OPUC-approved rate schedule that includes service and site-specific qualifications.

Third Party Optimization. NW Natural has a contract with an independent energy marketing company to optimize the value of our assets, primarily through the use of commodity transactions and capacity release transactions. See Part II, Item 7., "Comparison of Gas Distribution Operations—Business Segments Other than Local Gas Distribution—Gas Storage."

Other

We have other non-regulated investments, including assets in NNG Financial Corporation (Financial Corporation) (see "Subsidiaries," below), a Boeing 737-300 aircraft leased to Continental Airlines and miscellaneous other investments in non-regulated activities. Less than 1 percent of our consolidated assets and about 1 percent of 2006 consolidated net income are related to activities in the "Other" business segment.

Subsidiaries

Financial Corporation

We currently operate one direct, active subsidiary, Financial Corporation. Financial Corporation, a wholly-owned subsidiary incorporated in Oregon, holds financial investments including limited partnership interests in two wind power electric generation projects located in California and two low-income housing projects Portland, Oregon. In January 2005, Financial Corporation sold its limited partnership interests in three solar electric generating plants located in California. Financial

Corporation also has one active, wholly-owned subsidiary, KB Pipeline Company (KB Pipeline), which owns a 10 percent interest in an 18-mile interstate natural gas pipeline. As a part owner of the pipeline, KB Pipeline is subject to certain regulations enacted by FERC with respect to the Standards of Conduct for Transmission providers.

Gas Supply, Storage and Transportation Capacity

General

We meet the expected needs of our core utility customers through natural gas purchases from a variety of suppliers. Our supply and capacity plan is based on forecasted system requirements and takes into account estimated load growth by type of customer, attrition, conservation, distribution system constraints, interstate pipeline capacity and contractual limitations and the forecasted movement of customers between bundled sales service and transportation-only service. Sensitivity analyses are performed based on factors such as weather variations and price elasticity effects. We have a diverse portfolio of short-, medium- and long-term firm gas supply contracts that we supplement during periods of peak demand with gas from storage facilities either owned by or contractually committed to us.

Gas Acquisition Strategy

Our goals in purchasing gas for our core utility market consist of:

- ***Reliability***—Ensuring a gas resource portfolio that is sufficient to satisfy core utility customer requirements under design-day weather conditions, as defined in our Integrated Resource Plan (see "Regulation and Rates—Integrated Resource Plan," below);
- ***Lowest reasonable cost***—Applying strategies to acquire gas supplies at the lowest reasonable cost to utility customers;
- ***Price stability***—Making use of physical assets (e.g. gas storage) and financial instruments (e.g. financial hedge contracts such as price swaps) to manage price variability; and
- ***Cost recovery***—Managing gas purchase costs prudently to minimize the risks associated with regulatory review and recovery of gas acquisition costs.

To achieve those goals, we employ a gas purchasing strategy based upon a diversity of supply, liquidity, price risk management, asset optimization and regulatory alignment, as discussed in more detail below.

Diversity of Supply. There are three means by which we diversify our gas supply acquisitions: regional supply basin, contract types and contract duration.

The following table represents the actual and target purchase percentages from the regional sources of gas available to us:

Regional Supply Basin		
Region	2006 Actual	2006-2011 Target
Alberta	41%	45%
British Columbia	29%	30%
U.S. Rockies	30%	25%
Mist gas field	<1%	<1%
Total	100%	100%

We believe that gas supplies available in the western United States and Canada are adequate to serve our core utility customers for the foreseeable future, and that our cost of gas generally will track market prices.

We typically enter into gas purchase contracts for:

- year-round baseload supply;
- November–March (winter heating season) baseload supply;
- winter heating season contracts where we have the option to call on all, some or none of the supplies on a daily basis; and
- spot purchases, taking into account forecasted customer requirements, storage injections and withdrawals and seasonal weather fluctuations.

Other less frequent types of contracts include April-October baseload contracts, April-October contracts where the supplier has the option to supply gas to us on a daily basis, and seasonal exchange purchase and sale contracts. In general, we try to maintain a diversified portfolio of purchase arrangements. For example, we use a variety of multi-year contract durations to avoid having to re-contract all supplies every year. See "Core Utility Market Basic Supply," below.

Liquidity. We purchase our gas supplies at liquid trading points to facilitate competition and price transparency. These trading points include the NOVA Inventory Transfer (NIT) point in Alberta (also referred to as AECO), Huntingdon/Sumas and Station 2 in British Columbia, and various receipt points in the Rocky Mountains.

Price Risk Management. There are four general methods that we currently use for managing gas commodity price risk:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial instruments that exchange the floating price in a physical supply contract for a fixed price (referred to as price swaps);
- negotiating financial instruments that set a ceiling and/or floor price on a floating price contract (referred to as call and put options, respectively); and
- buying gas and injecting it into storage. See "Cost of Gas," below.

Asset Optimization. We use our gas supply, storage and transportation flexibility to capture opportunities that emerge during the course of the year for gas purchases, sales, exchanges or other means to manage net gas costs. In particular, our Mist underground storage facility provides flexibility in this regard. In addition to our own activities to economically manage our gas supply costs, we contract with an independent energy marketing company to more fully capture optimization opportunities.

Regulatory Alignment. Mechanisms for gas cost recovery are designed to be fair and balanced for customers and shareholders. In general, we do not earn a return on the gas commodity purchased, and we attempt to minimize risks associated with cost recovery through:

- the use of purchased gas adjustment (PGA) mechanisms approved by the OPUC and WUTC (see "Regulation and Rates—Rate Mechanisms," below);
- aligning customer and shareholder interests through an incentive sharing mechanism for the PGA and asset optimization mechanisms; and
- periodic review of regulatory deferrals with state regulatory commissions and key customer groups.

Cost of Gas

The cost of gas to supply our core utility market primarily consists of the purchase price paid to suppliers, charges paid to pipelines to transport the gas to our distribution system and gains or losses related to hedge contracts entered into in connection with supply of gas to core customers. While the rates for pipeline transportation and storage services are subject to federal regulation, the purchase price of gas is not.

Supply cost. Natural gas commodity prices increased dramatically over the last six years due to growing demand for natural gas, especially for power generation, stagnant North American gas production, surging alternative fuel prices, and the impact in 2005 of hurricane activity that affected oil and natural gas production in the Gulf of Mexico. We are in a favorable position with respect to gas production because of the proximity of our service territory to supply basins in western Canada and the Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future.

Transportation cost. Pipeline transportation rates had been relatively stable in recent years, but two of the five major pipelines used by NW Natural filed for significant rate increases in 2006. Pipeline transportation rate increases are generally recoverable through our state-approved PGA mechanisms. See "Regulation and Rates—Interstate Pipeline Rate Cases," below.

Hedging. We seek to mitigate the effects of higher gas commodity prices and price volatility on core utility customers by using our underground storage facilities strategically, by entering into natural gas commodity-based financial hedge contracts, and by crediting gas costs with margin revenues derived from off-system sales of commodity supplies and released transportation capacity in periods when core utility customers do not fully utilize firm pipeline transportation capacity and gas supplies.

Managing the Cost of Gas

We manage natural gas commodity price risk through an active hedging program in which we enter into either fixed price physical supply contracts or fixed price financial derivatives contracts. The financial contracts make up a majority of our commodity price hedging activity and these contracts are with a variety of investment-grade credit counterparties, typically with credit ratings of AA- or higher. See Part II, Item 7A., "Market Risk—Credit Risk—Credit exposure to financial derivative counterparties." Under this program, we enter into commodity swap, put and call option agreements for the coming year and up to three years into the future. Gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas. The intended effect of this program is to lock in prices for a majority of our gas supply portfolio for the following gas contract year, including at least 50 percent of the expected heating season purchases, based on the market prices and forecasted purchase requirements prevailing at the time the financial agreements are entered into. Prices have been secured for less than 50 percent of gas purchases in subsequent gas contract years, but maintaining some longer term hedging in future years helps to stabilize future gas costs and reduces variations in annual customer rate changes.

In addition to the volumes for which prices are locked in through financial hedges, we also use gas storage as a physical hedge. We purchase and inject about 15 percent of our annual gas supply requirements into storage during the summer when gas prices are historically lower. That gas is stored for withdrawal during the winter months in five different storage facilities. We own and operate three of these storage facilities located within our service territory, which eliminates the need for additional upstream pipeline capacity and provides significant cost savings.

Source of Supply—Design Day Sendout

The effectiveness of our gas supply program ultimately rests on whether we provide reliable service at a reasonable cost to our core customers. To assure reliability, we base our plans on being able to meet the supply needs on the coldest weather experienced over the last 20 years in our service territory. We start with the coldest overall heating season and then modify it to include the coldest weather day over that same 20 year period. This coldest "design day" is the maximum anticipated demand on the natural gas distribution system during a 24-hour period, which currently assumes weather at an average temperature of 12 degrees Fahrenheit. We assume that all interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout total approximately 8.9 million therms. We are currently capable of meeting 63 percent of our firm customer design day requirements with storage and peaking supply sources located within or adjacent to our service territory. Optimal utilization of storage and peaking facilities on our design day reduces the dependency on firm transportation. On January 5, 2004, we experienced our current-record firm customer sendout of 7.2 million therms, and a total sendout of 8.9 million therms, on a day that was approximately 9 degrees Fahrenheit warmer than the design day temperature. That January 2004 cold weather event lasted about 10 days, and the actual firm customer sendout each day provided data indicating that load forecasting models required very little re-calibration. Accordingly, we believe that our supplies would be sufficient to meet firm customer demand if we are to experience design day conditions.

The following table reflects the sources of supply that are projected to be used to satisfy the design day sendout for the 2006-2007 winter heating season:

Projected Sources of Supply for Design Day Sendout

	Therms (in milions)	Percent
Sources of Supply		
Firm Contracts	3.25	37
Off-system storage	1.06	12
Mist underground storage (utility only)	2.30	26
LNG storage	1.80	20
Recall agreements	0.45	5
Total	8.86	100

We believe the combination of the natural gas supply purchases under contract, our peaking supplies and the transportation capacity held under contract on the interstate pipelines are sufficient to satisfy the needs of existing customers and are positioned to grow, as needed, to meet requirements in future years.

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in the western United States and Canada. As shown above, about 70 to 75 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. At January 1, 2007, we had 21 firm contracts with 10 suppliers and remaining terms ranging from three months to eight years, which provide for a maximum of 1.7 million therms of firm gas per day during the peak winter heating season and 1.2 million therms per day during the remainder of the year. These contracts have

a variety of pricing structures and purchase obligations. During 2006, we purchased 833 million therms of gas under the following contract durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (one year or longer)	54%
Short-term (more than one month, less than a year)	19%
Spot (less than one month)	27%
Total	100%

We regularly renew or replace our expiring long-term gas supply contracts with new agreements from a variety of existing and new suppliers. Aside from the optimization of our core utility gas supplies by the independent energy marketing company (see "Gas Acquisition Strategy—Asset Optimization," above), four suppliers each amount to between 12.5 percent and 14.8 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to eight years. All term gas supply contracts use price formulas tied to monthly index prices, primarily at the NIT trading point in Alberta. We hedge a majority of these contracts each year using financial instruments as part of our gas purchasing strategy (see "Managing the Cost of Gas," above).

In addition to the year-round contracts, we continue to contract in advance for firm gas supplies to be delivered only during the winter heating season primarily under short-term contracts. During 2006, new short-term purchase agreements were entered into with four suppliers. These agreements have a variety of pricing structures and provide for a total of up to 500,000 therms per day during the 2006-2007 heating season. We intend to enter into new purchase agreements in 2007 for equivalent volumes of gas with our existing or other similar suppliers, as needed, to replace short-term and one-year contracts that will expire during 2007.

We also buy gas on the spot market as needed to meet demand. We have flexibility under the terms of some of our firm supply contracts enabling us to purchase spot gas in lieu of firm contract volumes, thereby allowing us to take advantage of favorable pricing on the spot market from time to time.

We continue to purchase gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facility. The price for this gas is tied to our weighted average cost of gas. Current production is approximately 10,000 therms per day from about 14 wells, supplying less than 1 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

Core Utility Market Peaking Supply and Storage

We supplement our firm gas supplies with gas from storage facilities either owned or contractually committed to us. Gas is generally purchased and stored during periods of low demand for use during periods of peak demand. In addition to enabling us to meet our peak demand, these facilities make it possible to lower the annual average cost of gas by allowing us to minimize our pipeline transportation contract demand costs and to purchase gas for storage during the summer months when prices are historically lower.

Underground storage. We have contracts with Northwest Pipeline Corporation (Northwest Pipeline) for firm gas storage services from an underground storage facility at Jackson Prairie near Chehalis, Washington, and an LNG facility at Plymouth, Washington. Together, these facilities

provide us with daily firm deliverability of about 1.1 million therms and total seasonal capacity of about 16 million therms. Separate contracts with Northwest Pipeline provide for the transportation of these storage supplies to our service territory. All of these contracts have reached the end of their primary terms, but we have exercised our renewal rights that allow for annual extensions at our option.

We also provide daily and seasonal peaking from our underground gas storage facility in the Mist gas field. Including the latest expansions in 2005, this facility has a maximum daily deliverability of 4.4 million therms and a total working gas capacity of about 14 Bcf. In September 2004, we completed our South Mist pipeline extension project, which is a utility transmission pipeline from our Mist gas storage field to growing portions of our distribution service area. Also in 2004, a total of 400,000 therms per day of Mist storage capacity, which had been available for the non-utility gas storage business, was recalled and committed to use for core utility customers. This was the first instance of returning capacity that had been developed in advance of core utility customers' needs for interstate gas storage services under the regulatory agreement with the OPUC. Under this agreement, storage capacity is recalled as needed and added to utility rate base, at our original cost less accumulated depreciation, with a corresponding rate increase to customers to reflect the cost of service. No additional recalls of Mist capacity were required in 2005 or 2006. The core utility market now has 2.3 million therms per day of deliverability and approximately 9 Bcf of working gas committed from the Mist storage facility.

In December 2005, we completed our latest expansion of the Mist gas storage facility. This investment increased the facility's incremental capacity and total daily delivery capacity. All of this expansion is currently being used to serve growth in the gas storage market. Ultimately, this expansion also will be available to serve the needs of our core utility customers. The expansion increased working gas capacity at Mist to about 14 Bcf, with 5 Bcf allocated to the gas storage business segment. As the needs of core utility customers grow, existing storage capacity will be recalled and transferred for use by core utility customers and tracked into customer rates. As storage capacity is recalled to serve core utility customers, new storage capacity can be developed. Additional expansion at Mist is currently underway for customer use in 2007.

LNG. We own and operate two LNG plants in our service territory that liquefy gas during the summer months for storage until the peak winter heating season. These two plants provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 17 million therms.

Recallable capacity. We also have contracts with one electric generator and two industrial customers that together provide an additional 52,000 therms per day of year-round upstream capacity, plus 450,000 therms per day of recallable capacity and supply. Two of these three contracts renew from year to year, while the third will expire in 2010.

Transportation

Dependence on a Single Transportation Pipeline. Our distribution system is directly connected to a single interstate pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline is bi-directional as it transports gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the Rocky Mountain supply basins. The need for pipeline transportation diversity has been underscored by past Northwest Pipeline ruptures and the resulting federal order in 2003 that required Northwest Pipeline to replace its 26-inch mainline from the Canadian

border to our service territory. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify our pipeline transportation paths. Specifically, we are currently evaluating a potential pipeline project that would connect TransCanada Pipelines Limited's (TransCanada) ıs Transmission Northwest (GTN) interstate transmission line to our gas distribution system. This project could provide an alternate transportation path for gas purchases in Alberta that currently move through the Northwest Pipeline system.

Rates. Rates for pipeline transportation are established by FERC for service under long-term transportation agreements with the U.S. interstate pipelines and by Canadian federal or provincial authorities for service under agreements with the Canadian pipelines over which we ship gas.

Transportation Agreements. The largest of our transportation agreements with Northwest Pipeline extends through 2013 and provides for firm transportation capacity of up to 2.1 million therms per day. This agreement provides access to natural gas supplies in British Columbia and the U.S. Rocky Mountains.

Our second largest transportation agreement with Northwest Pipeline extends through 2011. It provides 1.0 million therms per day of firm transportation capacity from the point of interconnection of the Northwest Pipeline and GTN systems in eastern Oregon to our service territory. GTN's pipeline runs from the U.S./Canadian border through northern Idaho, southeastern Washington and central Oregon to the California/Oregon border. We have firm long-term capacity on GTN and two upstream pipelines in Canada, which, with GTN, are business units of TransCanada, to match this amount of Northwest Pipeline capacity northward into Alberta, Canada.

We also have an agreement with Northwest Pipeline that extends through 2013 for approximately 350,000 therms per day of firm transportation capacity. This agreement accesses gas supplies in the U.S. Rocky Mountain region.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters. A contract with Duke Energy Gas Transmission (formerly Westcoast Energy, Inc.) extends through October 2014 and provides approximately 600,000 therms per day of firm gas transportation from Station 2 in northern British Columbia to the Huntingdon/Sumas connection with Northwest Pipeline at the U.S./Canadian border. A contract with Terasen Gas extends through October 2020 and provides approximately 470,000 therms per day of firm gas transportation from southeastern British Columbia to the same Huntingdon/Sumas connection with Northwest Pipeline. Our capacity with Terasen Gas is matched with companion contracts for pipeline capacity on the TransCanada BC System and NOVA system in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada. See "Regulation and Rates—Interstate Pipeline Rate Cases," below.

Regulation and Rates

We provide local distribution gas utility service in Oregon and Washington and, accordingly, we are subject to state regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. Local distribution service in Oregon represents over 90 percent of the utility's revenues.

NW Natural is exempt from FERC jurisdiction under Sections 1(b) and 1(c) of the Natural Gas Act (the Hinshaw exemption). We provide FERC-regulated orage services to interstate customers pursuant to a limited jurisdiction certificate from FERC.

General Rate Cases

Our most recent general rate increase in Oregon authorized rates designed to produce a return on shareholders' equity (ROE) of 10.2 percent and was effective September 1, 2003. Our most recent general rate case in Washington authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE and was effective July 1, 2004.

In May 2005, we reached a settlement with the FERC staff and all intervenors with respect to our rate case filed in January 2005 related to Mist interstate storage service. The settlement provided for a small net increase in the maximum rates for our interstate storage. These new maximum rates are designed to reflect updated costs related to development of the Mist gas storage facility since 2001 and costs associated with the South Mist pipeline extension project. The new rates were effective July 1, 2005.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA tariff mechanisms in Oregon and Washington to reflect changes in the total costs of natural gas commodity. The OPUC and the WUTC approved rate increases on October 25, 2006 that became effective on November 1, 2006, compared to October 1 in the prior year. The effect of the rate changes was to increase the average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential sales customers by 2.6 percent.

Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ from the amounts included in rates, we are required to defer a majority of that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, the utility recognizes in current earnings either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

In October 2006, the OPUC approved a modification to our PGA tariff, effective November 1, 2006, which provides that we use actual recoveries of gas costs in revenues billed (instead of using estimated gas costs incorporated in rates) compared to actual purchased gas costs to determine our PGA deferral. The effect of the new method is that changes in our line loss expense due to changes in unaccounted for gas volumes are deferred and included in the annual PGA mechanism. However, consistent with our prior PGA sharing mechanism, 67 percent of any cost differences for Oregon volumes is deferred for refund or recovery in customer rates in subsequent periods, while the remaining 33 percent is included in current earnings.

The OPUC has begun a formal review of the PGA process, which will cover portfolio requirements, incentive sharing levels and filing requirements, among other items. The investigation is expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected in the 2008 PGA filing.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a "conservation tariff," which is a rate mechanism designed to adjust margin for changes in average consumption patterns due to residential and commercial customers' conservation efforts. The tariff is a partial decoupling mechanism that is intended to break the link between earnings and the quantity of gas consumed by customers, removing any incentive for the utility to discourage customers'

conservation efforts. On average, residential and commercial customers have continued to reduce energy consumption over the past several years in response to the impact of higher energy prices on their utility bills and an increased awareness of energy efficiency measures and programs. In Washington, customer use is not covered a conservation tariff, and as such our utility earnings are affected by increases and decreases in usage based on customers' conservation efforts. Washington customers account for about 10 percent of utility revenues.

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for expected increases or decreases in customer volumes due to annual changes in commodity costs or periodic changes in our general rates; and (2) a conservation adjustment calculated on a monthly basis to account for deviations between actual and expected volumes (also referred to as the decoupling adjustment). The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the next year's annual PGA. Baseline consumption was determined by customer consumption data used in the 2003 Oregon general rate case, adjusted for new customers. See Part II, Item 7., "Results of Operations—Comparison of Gas Distribution Operations."

In 2005, an independent study to measure the Oregon tariff mechanism's effectiveness recommended continuation of the conservation tariff with minor modifications. In 2005 and 2006, the OPUC approved the continuation of the conservation tariff through September 30, 2009 and increased the mechanism's coverage from a partial decoupling of 90 percent of residential and commercial gas usage to a full decoupling of 100 percent.

Weather Normalization. In November 2003, the OPUC authorized, and the utility implemented, a weather normalization mechanism in Oregon that helps stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather. The current normalization mechanism is applied to our residential and commercial customers' bills between December 1 and May 15 for each heating season. The mechanism adjusts the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. We do not have a weather normalization mechanism approved for our Washington customers, which account for about 10 percent of our utility revenues.

Excess Earnings Test. The OPUC's annual formal review process to test for excess earnings ensures that we are allowed to pass through 100 percent of prudently incurred gas costs into rates. We are subject to an excess earnings test requirement in which we retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. Revenues equivalent to 33 percent of any earnings above the threshold are required to be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year based on movements in long-term interest rates. In 2006 and 2005, the threshold after adjustment was 13.44 percent and 13.32 percent, respectively. No amounts were required to be refunded to customers as a result of the 2005 or 2004 earnings test. We do not expect any amounts to be refunded to customers as a result of the 2006 earnings test, which will be reviewed by the OPUC during the second quarter of 2007. In Washington, we are not subject to an annual excess earnings test, and 100 percent of all prudently incurred gas costs are passed through into customer rates.

Recent Changes in Industrial Tariffs. In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial accounts. The changes set out additional

parameters to provide more certainty in the level of gas supplies we will need to acquire to serve this customer group. The parameters include an annual election period, ·ıecial pricing provisions for out-of-cycle changes and a requirement that customers on our annual weighted average cost of gas tariff complete the term of their service :ction.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved our application relating to the accounting treatment and full recovery for the cost of the pipeline integrity management program, as mandated by the Pipeline Safety Improvement Act of 2002 and related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration. The accounting and rate treatment for these costs extends through September 30, 2008 and may be reviewed for potential extension after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed general rate increase cases with the FERC. See Part II, Item 7., "Results of Operations—Regulatory Matters—Interstate Pipeline Rate Cases". Increases in interstate pipeline transportation expenses are subject to our PGA deferral mechanism and are 100 percent passed-through to customers in both Oregon and Washington. Pipeline transportation demand charges are not subject to the 33 percent incentive sharing mechanism in Oregon. Both of these increases in pipeline transportation rates were included in our 2006 PGA rates. In February 2007, Northwest Pipeline filed a settlement proposal with the FERC that would resolve all issues with the active parties and would result in an increase in our transportation rates of about $12.0 million. Amounts collected from our utility customers in excess of this settlement amount will be deferred and returned to customers in our next PGA rate filing in late 2007.

Integrated Resource Plan

The OPUC and WUTC have implemented integrated resource planning processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. Our most recent integrated resource plan was filed in Oregon and Washington in 2005. Elements of the plan included:

- an evaluation of supply and demand resources;
- the consideration of uncertainties in the planning process and the need for flexibility to respond to changes;
- a primary goal of "least cost" service; and
- consistency with state energy policy.

Although the OPUC's order acknowledging the integrated resource plan does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. ¯lements of our draft integrated resource plan demonstrate that the continued development of the Mist underground gas storage facility is the least-cost option for .rving customer growth. We expect to file an updated plan in 2007.

Additions to Infrastructure

We expect a high level of capital expenditures for additions to infrastructure over the next five years, reflecting projected customer growth, technology, system replacement, improvement and

reinforcement projects and the development of additional gas storage facilities. Estimated capital expenditures in 2007 total about $110 million, and for the years 2007-'11 capital expenditures are estimated at between $500 and $600 million. We continue to be one of the fastest growing gas utilities in the nation (see "Competition and Marketing," below). In 2006, our customer base grew by more than 3 percent for the 20th year in a row.

Pipeline Safety

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act) was signed into law in December 2006. The 2006 Act mandates certain standards related to our distribution lines, including a development of integrity management programs for those distribution pipelines. We do not anticipate any material impacts during 2007, but do expect changes related to the 2006 Act to begin to impact us in 2008.

The Pipeline Safety Improvement Act of 2002 (Act) and related regulations require gas transmission pipeline operators to identify lines located in High Consequence Areas (HCAs) and develop integrity management programs to periodically inspect the integrity of the pipelines and make repairs or replacements as necessary to ensure the ongoing safety of the pipelines. The legislation and related pipeline safety regulations require us to complete inspection of 50 percent of the highest risk pipelines located in our HCAs within the first five years, and the remaining covered pipelines within 10 years, of the date of enactment. We are also required to re-inspect the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines. We have met the first major milestone required by the Act and are on track to complete the next milestone, which is to complete the inspection of 50 percent of our highest risk transmission pipelines by the end of 2007.

Effective January 12, 2005, we assumed responsibilities as operator of an approximately 60-mile pipeline that transports gas from Northwest Pipeline to Coos County, Oregon. The pipeline is owned by Coos County, and we have an agreement to operate the pipeline and related lateral pipelines that runs yearly until terminated by either party. The pipeline safety requirements of the Act apply to us as operator of that pipeline.

In 2001, we entered into a stipulation with the OPUC for an enhanced pipeline safety program that includes an accelerated bare steel replacement program and a geo-hazard safety program. The bare steel program accelerates the replacement of our bare steel piping over 20 years instead of 40 years and allows us to receive rate treatment for costs associated with the program exceeding $3 million per year. The geo-hazard component of the safety program expired on December 31, 2006. It included the identification, assessment and remediation of risks to piping infrastructure created by landslides, washouts, earthquakes or similar occurrences, and allowed us to receive deferred rate treatment for costs associated with the program. Although the regulatory authority for the geo-hazard safety program expired, we received approval from the OPUC to defer the costs up to $2.5 million associated with a specific remediation project, which is expected to be completed in 2007.

Competition and Marketing

Competition with Other Energy Products

We have no direct competition in our service area from other natural gas distributors. However, for residential customers' heating needs, we compete with electricity, fuel oil, propane and, to a lesser extent, wood. We also compete with electricity and fuel oil for commercial applications. In the

industrial market, we compete with all forms of energy, including gas-to-gas competition from third-party sellers of natural gas commodity. Competition among these forms of energy is based on price, reliability, efficiency and performance.

The slight competitive price advantage of natural gas over electricity was maintained in 2006 as natural gas commodity prices began to moderate and electricity prices remained stable in both the residential and commercial markets. The current price advantage varies due to differences in retail electric rates between investor-owned utilities, where we have maintained a moderate price advantage, and public utilities, where our price advantage, if any, is marginal. In 2006, although electricity prices continued to become more competitive primarily due to higher gas prices and improving end use technology for heat pumps, natural gas retained its relative price advantage compared to electricity provided by the investor-owned utilities that serve approximately 75 percent of the homes in our Oregon service area. We expect to maintain a price advantage compared to electricity from the investor-owned electric utilities in part because a growing portion of the electricity sold by these utilities is generated using natural gas.

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at approximately 50 percent, together with the price advantage of natural gas compared with electricity in most areas and our operating convenience over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2006, 18,449 net residential customers (after subtracting disconnected or terminated services) were added, primarily from single- and muti-family new construction, but also included existing residential housing that converted from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2006 was 19,421. This represents a growth rate of 3.1 percent, which is about twice the national average for local gas distribution companies as reported by the American Gas Association.

Industrial Markets

As a result of the deregulation and restructuring of the energy markets during the past two decades, the natural gas industry, including producers, interstate pipelines and local gas distribution companies, has undergone significant changes. Traditionally, local gas distribution companies sold a "bundled" product that included both the natural gas commodity and delivery to the end-use customer's meter. However, beginning in the late 1980s, large industrial customers sought to achieve savings by procuring their own supplies of natural gas from producers and contracting with pipelines and local gas distribution companies for transportation of natural gas to their facilities. These changes were intended to promote competition where it was economically beneficial to consumers.

Competition to serve the industrial and large commercial market in the Pacific Northwest has been relatively steady since the early 1990s in terms of numbers and types of competitors. Competitors consist of gas marketers, oil/propane sellers and electric utilities. Wood-based fuels continue to lose market share in these markets primarily due to environmental concerns and restrictions.

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs available to industrial customers are priced at our cost of providing transportation service. Generally, we are unaffected financially if industrial customers transport customer-owned gas rather than purchasing gas directly from us, as long as they remain on a tariff or contract with the same quality of service. This is because we do not

generally make any margin on the sale of the gas commodity. However, industrial customers may select between firm and interruptible service, among other different levels or qualities of service, and these choices can positively or negatively affect margin. The relative level and volatility of prices in the natural gas commodity markets, the availability of interstate pipeline capacity to ship customer-owned gas and the cost structure embedded in our industrial rates are among the primary factors that have caused some industrial customers to alternate between sales and transportation service or between higher and lower qualities of service.

We redesigned our industrial rates in Oregon and Washington as part of our general rate cases in 2003 and 2004, respectively, in order to better reflect relative costs of service and to become more competitive in the industrial market. In August 2006, the OPUC and WUTC approved further tariff changes to the service options for our industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to purchase in order to serve this customer group. The parameters include an annual election cycle period, special pricing provisions for out-of-cycle changes and the requirement that customers on our annual weighted average cost of gas tariff complete the agreed upon term of their service. In the case of customers switching out-of-cycle from transportation to sales service, the customer will be charged the cost of incremental gas supply under our regulatory tariff.

We have negotiated special transportation service agreements with some of our largest industrial customers. These special agreements are designed to provide transportation rates that are competitive with the customer's alternative capital and operating costs of installing direct connections to Northwest Pipeline's interstate pipeline system, which would allow them to bypass our gas distribution system. These agreements generally prohibit bypass during their terms. Due to the cost pressures that confront a number of our largest customers competing in global markets, bypass continues to be a threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we may experience further deterioration of margin associated with customers' transfers to contracts with pricing designed to be competitive with bypass.

Environmental Issues

Properties and Facilities

We have properties and facilities that are subject to federal, state and local laws and regulations related to environmental matters. These evolving laws and regulations may require expenditures over a long timeframe to control environmental effects. Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the ultimate selection of a particular technology;
- the level of remediation required; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

We own or previously owned properties currently being investigated that may require environmental response, including a property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site), a property adjacent to the Gasco site that is now the location of a manufacturing plant owned by Siltronic Corporation (Siltronic site), and an area adjacent to the Gasco and the Siltronic sites along a segment of the Willamette River that has been listed by the U.S. Environmental Protection Agency as a Superfund site for which we have been identified as one of a number of potentially responsible parties (Portland Harbor site). We do not expect that the ultimate resolution of these matters will have a material adverse effect on our financial condition or results of operations; however, if it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made and could have a material impact on our financial condition or results of operations. See Part II, Item 8, Note 12, to the accompanying Consolidated Financial Statements for a further discussion of potential environmental responses and related costs.

Future Environmental Issues

We recognize that our business is likely to face future carbon constraints. A variety of legislative and regulatory measures to address greenhouse gas emissions are in various phases of discussion or implementation. These include the proposed international standards (Kyoto Protocol), proposed federal legislation and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in greenhouse gas emissions. The outcome of federal and state climate change initiatives cannot be determined at this time, but these initiatives could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers. Because natural gas is a fossil fuel with a low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for electric production and direct use in homes and businesses. We have actively participated in policy development through the Oregon Governor's Task Force on Climate Change and are leading efforts within the American Gas Association to promote the enactment of fair climate change legislation. We recently created an Environmental Policy and Sustainability Department with responsibility for engaging in policy development and identifying ways to reduce greenhouse gas emissions associated with our operations.

Employees

At December 31, 2006, we had 1,211 employees, of which 815 were members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO. We have a labor agreement (Joint Accord) with members of OPEIU covering wages, benefits and working conditions that will expire on May 31, 2009.

Available Information

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). We make available on our website (http://www.nwnatural.com), free of charge, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, as well as proxy materials, filed or furnished pursuant to Section 13(a) or 15(d) and Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available on the website.

Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211.

Our Chief Executive Officer certified to the New York Stock Exchange (NYSE) on June 13, 2006 that, as of that date, he was not aware of any violation by the company of NYSE's corporate governance listing standards, and that we had filed with the SEC, as exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2005, the certificates of the Chief Executive Officer and the Chief Financial Officer certifying the quality of NW Natural's internal control over financial reporting and public disclosures. For the year-ended December 31, 2006, the certificates of the Chief Executive Officer and the Chief Financial Officer are filed with this report as Exhibits 31.1 and 31.2.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents we file with the SEC.

Regulatory risk. *The rates we charge customers for gas distribution services are established by the OPUC and the WUTC. The failure to approve rates which provide for recovery of our costs and an adequate return on invested capital may adversely impact our financial condition and results of operations.*

The rates and terms at which the utility resells gas to its customers or transports gas owned by large customers from the interstate pipeline connection to the customers' facilities must be approved by the OPUC or the WUTC. The rates are designed to allow us to recover costs of providing such services and to earn an adequate return on our capital investment. We expect to continue to make significant capital expenditures to expand and improve our distribution system. The failure of the OPUC or the WUTC to approve on a timely basis requested rate increases to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

Gas prices. *Higher natural gas commodity prices and fluctuations in the price of gas may adversely affect our earnings.*

In recent years, natural gas commodity prices have increased dramatically due to growing demand, especially for power generation, and stagnant North American gas production. In Oregon and in Washington, the utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas. The Oregon PGA tariff provides that 33 percent of any difference between the actual purchased gas costs and the actual recoveries of gas costs in rates be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

The OPUC has begun a formal review of the PGA process which will cover portfolio requirements, incentive sharing levels and filing requirements, among other items. The investigation is

expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected in the 2008 PGA filing.

Notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates, which also could adversely affect our results of operations.

Business risk. *Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and may expose us to additional liabilities for which rate recovery may be disallowed.*

Our gas purchasing requirements expose us to risks of commodity price movements. We attempt to manage our exposure through enforcement of established risk limits and risk management procedures, including hedging activities. These risk limits and risk management procedures may not always work as planned and cannot eliminate the risks associated with gas purchasing and hedging. These practices are subject to regulatory review in setting our PGA tariffs and, if found to be imprudent, could be disallowed, which could adversely affect our financial condition and results of operations.

Customer conservation. *Customers' conservation efforts may have a negative impact on our revenues.*

Higher gas costs and rates may result in increased conservation by customers, which can decrease sales and adversely affect results of operations. The OPUC authorized our conservation tariff, which is designed to recover lost margin due to changes in residential and commercial customers' consumption patterns. The conservation tariff is intended to adjust for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in general rates and for deviations between actual and expected usage. The conservation tariff expires in September 2009. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition and results of operations. We do not have a conservation tariff in Washington.

Environmental risks. *Certain of our properties and facilities may pose environmental risks requiring remediation, the cost of which could adversely affect our results of operations and financial condition. Also, management expects that future legislation may impose carbon constraints to address global climate change.*

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties, but our results of operations may be adversely affected to the extent that estimates of the probable costs increase significantly as additional information becomes available and to the extent we are not able to recover the incremental cost through customer rates or from insurance. A regulatory asset has already been recorded for some of these estimated costs. To the extent we are unable to recover these costs in rates or through insurance, then we would be required to reduce our regulatory asset which could adversely affect our results of operations and financial condition.

We cannot predict with certainty the amount or timing of future expenditures related to any environmental investigation and remediation that may be required because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. There are also no assurances

that existing environmental regulations will not be revised or that new stricter regulations seeking to protect the environment will not be adopted or become applicable to us. Revised environmental regulations which result in increased compliance costs or additional operating restrictions could have a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from customers.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers.

Competition. *Our gas distribution business is subject to increased competition and eroding price advantage.*

To the extent that competition increases, our profit margins may be negatively affected. In the residential market, we compete with suppliers of electricity, fuel oil, propane and, to a lesser extent, wood. We also compete with suppliers of electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy suppliers. Competition among these forms of energy is based on price, reliability, efficiency and performance.

Higher natural gas prices have eroded, or in some cases eliminated, the competitive price advantage of natural gas over alternative energy sources. If the higher gas price environment is sustained, our ability to attract new customers could be significantly affected, which could have a negative impact on our customer growth rate and results of operations.

Single transportation pipeline. *We rely on a single pipeline for the transportation of gas to our service territory.*

We are largely dependent on a single, bi-directional pipeline for transportation of gas into our service territory. Our results of operations may be negatively impacted if there is a rupture in the pipeline and we incur costs associated with actions taken to mitigate disruption of service.

Pension funding. *The cost of providing pension and other postretirement benefit plans is subject to changes in assumptions, fluctuations in the market value of plan assets and changes in demographics, all of which may have a material effect on our results of operations and cash flows.*

We maintain two qualified non-contributory defined benefit pension plans, several non-qualified supplemental pension plans and other postretirement benefit plans. We may be required to recognize a material increase or decrease in annual pension or postretirement benefit expense based on changes in assumed interest rates, market returns, expected rate of wage increases and other factors, and we may be required to record a charge to our balance sheet to the extent that projected benefit obligations exceed the fair value of plan assets.

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

Our gas distribution activities involve a variety of inherent operating hazards and risks, such as leaks, accidents, mechanical problems, fires, storms, landslides and other adverse weather conditions and hazards, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and disruption of our operations, which in turn could lead to substantial losses. The occurrence of any of these events may not be covered by our insurance policies or recoverable through rates, which could adversely affect our financial condition and results of operations.

Weather risk. *Our results of operations may be negatively affected by warmer than average weather.*

A large portion of the utility's margin is derived from sales to space heating residential and commercial customers during each winter heating season. Current rates are based on an assumption of average weather. In Oregon, the effects of warmer or colder weather on utility margin are reduced through the operation of our weather normalization mechanism and conservation tariff. However, 9 percent of eligible customers elected not to be covered by the weather normalization mechanism. Also, approximately 10 percent of our residential and commercial customers are in Washington where we do not have a weather normalization mechanism or conservation tariff. As a result, we are not fully protected against warmer than average weather, which may have an adverse affect on our financial condition, results of operations and cash flows.

Workforce risk. *Our business is heavily dependent on being able to attract and retain qualified employees and to maintain a competitive cost structure with market-based salaries and employee benefits.*

Our gas distribution business is subject to a variety of workforce risks, including being able to attract and retain qualified employees, being able to transfer the knowledge and expertise of an aging workforce to new employees as older workers retire and being able to reach collective bargaining agreements with the union that represents about 70 percent of our workers.

Customer growth. *Our results of operations may be negatively affected by our ability to sustain customer growth.*

Our earnings growth and results of operations have largely been dependent upon the sustained growth of our residential and commercial customer base at an annual rate of over 3 percent. If we are unable to sustain these levels of customer growth, our results of operations may be negatively affected. A number of factors could negatively impact our ability to sustain growth, such as a downturn in the economy, reduced housing starts and competition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Our natural gas distribution system consists of 13,474 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the distribution system includes service pipes, meters and regulators, and gas regulating and metering stations. The mains are located in municipal streets or alleys pursuant to valid franchise or occupation ordinances, in county

roads or state highways pursuant to valid agreements or permits granted pursuant to statute, or on lands of others pursuant to valid easements obtained from the owners of such lands. We also hold all necessary permits for the crossing of the Willamette River and a number of smaller rivers by our mains.

We own service facilities in Portland, as well as various satellite service centers, garages, warehouses and other buildings necessary and useful in the conduct of our business. We lease office space in Portland for our corporate headquarters, which lease expires on May 31, 2018. District offices are maintained on owned or leased premises at convenient points in the distribution system. We own LNG storage facilities in Portland and near Newport, Oregon.

We hold interests in 8,624 net acres of underground natural gas storage and 1,780 net acres of oil and gas leases in Oregon. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field.

In order to reduce risks associated with gas leakage in older parts of our system, we undertook an accelerated pipe replacement program under which we removed or replaced 100 percent of our cast iron mains by October 2000. In 2001, we initiated an accelerated pipe replacement program under which we will reduce the amount of bare steel mains in the system.

We consider all of our properties currently used in our operations, both owned and leased, to be well maintained, in good operating condition, and, along with planned additions, adequate for our present and foreseeable future needs.

Our Mortgage and Deed of Trust is a first mortgage lien on substantially all of the property constituting our utility plant.

ITEM 3. LEGAL PROCEEDINGS

See Note 12 to Consolidated Financial Statements, "Commitments and Contingencies—Legal Proceedings."

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the quarter ended December 31, 2006.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(A) Our common stock is listed and trades on the New York Stock Exchange under the symbol "NWN."

The high and low trades for our common stock during the past two years were as follows:

	2006		2005	
Quarter Ended	High	Low	High	Low
March 31	$ 36.57	$ 32.83	$ 37.24	$ 32.42
June 30	37.04	33.30	38.67	34.36
September 30	40.08	35.81	39.63	35.60
December 31	43.69	38.53	37.77	33.25

The closing quotations for our common stock on December 29, 2006 and December 30, 2005 were $42.44 and $34.18, respectively.

(B) As of December 31, 2006, there were 8,753 holders of record of our common stock.

(C) We have paid quarterly dividends on our common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments have increased each year since 1956. Dividends per share paid during the past two years were as follows:

Payment Date	2006	2005
February 15	$ 0.345	$ 0.325
May 15	0.345	0.325
August 15	0.345	0.325
November 15	0.355	0.345
Total per share	$ 1.390	$ 1.320

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. It is the intention of the Board of Directors to continue to pay cash dividends on our common stock on a quarterly basis. However, the declaration and amount of future dividends will be dependent upon our earnings, cash flows, financial condition and other factors.

(D) The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Exchange Act during the quarter ended December 31, 2006:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Pl
Balance forward			812,700	$ 60,260,697
10/01/06-10/31/06	1,380	$ 40.27	70,000	(2,851,596)
11/01/06-11/30/06	22,576	$ 40.90	113,400	(4,571,685)
12/01/06-12/31/06	1,742	$ 42.72	165,000	(6,937,500)
Total	25,698		1,161,100	$ 45,899,916

(1) During the quarter ended December 31, 2006, 24,901 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan (DSPP). In addition, 797 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended December 31, 2006, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program that has been extended annually. In April 2006, the Board extended the program through May 31, 2007 and increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. Share repurchases are made in the open market or through privately negotiated transactions. During the three months ended December 31, 2006, 348,400 shares of our common stock were purchased pursuant to this program. Since the program's inception, we have repurchased 1,161,100 shares of common stock at a total cost of $39.1 million.

On September 29, 2006, we entered into a Stock Purchase Plan Engagement Agreement with our broker in order to establish a trading plan for our repurchase program that qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Securities Exchange Act of 1934, as amended. The agreement expired on December 31, 2006.

ITEM 6. SELECTED FINANCIAL DATA

Thousands, except per share amounts and ratio of earnings to fixed charges	For the year ended Dec. 31, 2006	2005	2004	2003	2002
Utility operating revenues:					
Residential sales	$ 536,468	$ 471,502	$ 383,067	$ 328,346	$ 354,735
Commercial sales	290,666	250,287	200,424	176,336	201,475
Industrial - firm sales	66,986	64,507	45,259	33,578	42,965
Industrial - interruptible sales	93,107	100,740	55,380	23,655	15,937
Unbilled revenues[1]	-	-	-	14,474	(12,702)
Total gas sales revenues	987,227	887,036	684,130	576,389	602,410
Transportation	12,800	10,755	12,655	17,968	26,020
Other	161	2,862	4,160	7,627	4,018
Total gross utility operating revenues	1,000,188	900,653	700,945	601,984	632,448
Cost of gas sold	648,081	563,772	399,176	323,128	353,034
Revenue taxes	24,840	21,633	16,865	14,650	14,743
Utility operating revenues	327,267	315,248	284,904	264,206	264,671
Non-utility operating revenues	12,909	9,745	6,591	9,210	8,130
Net operating revenues	$ 340,176	$ 324,993	$ 291,495	$ 273,416	$ 272,801
Net income	$ 63,415	$ 58,149	$ 50,572	$ 45,983	$ 43,792
Redeemable preferred and preference stock dividend requirements	-	-	-	294	2,280
Earnings applicable to common stock	$ 63,415	$ 58,149	$ 50,572	$ 45,689	$ 41,512
verage common shares outstanding:					
Basic	27,540	27,564	27,016	25,741	25,431
Diluted	27,657	27,621	27,283	26,061	25,814
Earnings per share of common stock:					
Basic	$ 2.30	$ 2.11	$ 1.87	$ 1.77	$ 1.63
Diluted	$ 2.29	$ 2.11	$ 1.86	$ 1.76	$ 1.62
Dividends per share of common stock	$ 1.39	$ 1.32	$ 1.30	$ 1.27	$ 1.26
Total assets – at end of period	$ 1,956,856	$ 2,042,304	$ 1,732,195	$ 1,585,379	$ 1,467,277
Redeemable preferred stock	$ -	$ -	$ -	$ -	$ 8,250
Long-term debt	$ 517,000	$ 521,500	$ 484,027	$ 500,319	$ 445,945
Ratio of earnings to fixed charges	3.40	3.32	3.02	2.84	2.85

[1] Unbilled revenues have been allocated by class for 2006, 2005 and 2004.

Certain amounts from prior years have been reclassified to conform, for comparison purposes, with the current financial statement presentation. These reclassifications had no impact on prior year consolidated results of operations.

SELECTED FINANCIAL DATA (continued)

Thousands, except customer and gas cost per therm

data	2006	2005	2004	2003	2002
Capitalization - at end of period					
Common stock equity	$ 599,545	$ 586,931	$ 568,517	$ 506,316	$ 482,392
Redeemable preferred stock	-	-	-	-	8,250
Long-term debt	517,000	521,500	484,027	500,319	445,945
Total capitalization	$ 1,116,545	$ 1,108,431	$ 1,052,544	$ 1,006,635	$ 936,587
Gas sales and transportation deliveries (therms):					
Residential	382,665	371,538	352,356	343,534	357,091
Commercial	242,683	233,987	222,875	226,257	240,155
Industrial - firm	66,971	74,880	62,843	55,314	63,215
Industrial - interruptible	112,736	149,106	104,278	47,994	26,241
Unbilled therms[1]	-	-	-	12,099	(6,617)
Total gas sales	805,055	829,511	742,352	685,198	680,085
Transportation	387,594	328,056	389,514	414,554	445,999
Total volumes delivered	1,192,649	1,157,567	1,131,866	1,099,752	1,126,084
Customers (average for period):					
Residential	564,700	545,163	525,976	510,336	492,871
Commercial	59,889	58,914	57,973	56,504	55,416
Industrial - firm	650	666	629	362	350
Industrial - interruptible	197	201	178	98	74
Transportation	99	78	106	179	190
Total customers	625,535	605,022	584,862	567,479	548,901
Customer statistics:					
Heat requirements:					
Actual degree days	4,089	4,178	3,853	3,952	4,232
Percent colder (warmer) than average	(4%)	(2%)	(10%)	(7%)	(1%)
Average annual use per customer in therms:					
Residential	678	682	670	673	725
Commercial	4,052	3,972	3,844	4,004	4,334
Gas purchased cost per therm - net (cents)	75.37	71.42	56.60	46.99	51.07

[1] Unbilled therms have been allocated by class for 2006, 2005 and 2004.

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

The following is management's assessment of Northwest Natural Gas Company's financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the three years ended December 31, 2006. References in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements include the accounts of Northwest Natural Gas Company, which principally consists of our regulated local gas distribution business, our regulated gas storage business, and our other non-regulated businesses, which includes our wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation). In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business segment (gas storage), previously referred to as "interstate gas storage," and our other non-regulated activities (other) (see Note 2).

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on earnings. All references in this report to earnings per share are on the basis of diluted shares (see Note 1, "Earnings Per Share").

Executive Summary

Our strategy in 2006 was to remain focused on profitably growing our regulated utility and gas storage businesses. The utility is our largest business segment with approximately 98 percent of consolidated total assets, which contributed 90 percent of consolidated net income in 2006. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring an adequate supply of gas, providing distribution services at a competitive price, and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

Our gas storage segment represents approximately 2 percent of consolidated total assets and contributed 9 percent of consolidated net income in 2006. This business unit primarily provides firm and interruptible gas storage at our Mist underground storage facility to large interstate and intrastate customers using storage and related transportation capacity that is in excess of our utility's core (residential, commercial and industrial firm) customer requirements. Asset optimization is also part of the gas storage segment, with optimization services provided for the utility under an agreement with an independent energy marketing company. Factors critical to the success of our gas storage business segment include the ability to: develop additional storage capacity at competitive market prices; plan for the replacement of capacity that is expected to be recalled by the utility to serve its core customers in the future; and obtain timely and reasonable rate changes.

Highlights of 2006 include:

- Net income and diluted earnings per share increased 9 percent in 2006, to $63.4 million and $2.29 per share;

- Solid growth in net operating revenues from our regulated utility distribution and gas storage businesses were major drivers to increased earnings in 2006;
- Net operating revenues from our regulated utility increased 4 percent to $327.3 million, largely attributable to strong customer growth, which increased by more than 3 percent for the 20th consecutive year, and increased margin sharing from gas cost savings through our regulatory incentive mechanism;
- Net operating revenues from gas storage increased 33 percent to $12.8 million, including a higher amount of revenue sharing with our utility customers, which increased 43 percent to $7.0 million;
- Operations and maintenance expense increases were held to 1 percent in 2006, including incremental costs for employee retirement and severance programs and employee bonuses tied to improved financial results which were largely offset by cost reductions from business process redesign initiatives that we began implementing in 2006;
- Cash flow from operations increased 88 percent to $148.6 million, reflecting strong operating and working capital results;
- $25 million of new long-term debt was issued in the fourth quarter of 2006, with the proceeds being used to redeem short-term debt and fund capital expenditures;
- In a J.D. Power & Associates' residential customer survey, NW Natural ranked first in the nation for customer satisfaction with billing and payment services, and third in the nation for overall customer satisfaction among the 56 largest gas utilities; and,
- Our quarterly common stock dividend rate increased 3 percent to $0.355 per share in the fourth quarter of 2006, making this the 51st consecutive year of increasing dividends paid to shareholders.

Issues, Challenges and Performance Measures

A number of factors affect our operations and financial performance. The most significant issue the utility faces in the near term is high gas prices. Wholesale gas prices over the past few years have increased significantly, primarily due to increasing demand. In 2005, the gas supply market tightened significantly as hurricanes hit parts of the United States, resulting in the disruption of gas supplies and causing gas prices to spike. Since then, gas prices have moderated and are now relatively more stable than last year. We expect energy prices to remain slightly higher than in the past few years, with higher gas prices already reflected in our customers' bills for the 2006-07 heating season. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but further price increases for gas could change our competitive advantage and our customers' preference for natural gas. If higher gas prices persist, it could significantly affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses' energy needs to alternative fuel sources. To address these competitive issues, we are continually developing new gas acquisition strategies to manage gas prices and meet market demands, and we are working on initiatives intended to improve operational efficiencies throughout the company through a comprehensive business process redesign effort (see "Business Process Redesign," below).

Other issues and challenges we expect to face in 2007 include executing on our business process redesign initiatives, managing gas supplies and prices under unpredictable market conditions, managing the potential impact of adverse regulatory actions or policy changes, managing storage and transportation capacity, managing and maintaining customer growth, maintaining a competitive advantage over alternative fuels and managing environmental risks and exposures and higher interest rates. For a more detailed discussion of these and other risks, see "Part I, Item 1A—Risk Factors,"

above, "Item 7A., Quantitative and Qualitative Disclosures About Market Risk," below, and "Forward-Looking Statements," below, following Item 7A.

Our strategic plan addresses the risks affecting our business by focusing on:

- improving our ability to add customers profitably;
- managing wholesale natural gas prices through an active hedging program to keep customer prices stable and as low as possible;
- maintaining our reputation for exemplary customer service;
- reducing business risks;
- managing all costs, including capital investments;
- maintaining a strong financial position;
- improving our cost structure through business process redesign initiatives; and
- judiciously growing beyond our local distribution business where such growth would complement our core assets and competencies.

Return on invested capital and common equity ratios are key indicators of our operating performance and financial condition. We compare our utility return on equity results each year against the return authorized by the OPUC. We also compare our total shareholder return (stock price appreciation plus dividends) against a peer group of local gas distribution companies because it is necessary for us to attract investors so that we can continue to cost-effectively raise the capital needed to run our businesses. Other key performance measures we use in monitoring progress against our goals include earnings per share, cash provided by operations, free cash flow (cash from operations less payments for investing activities and dividends), customer satisfaction ratings, customer additions, operations and maintenance expense per customer, construction cost per meter installed and non-revenue producing capital expenditures per customer.

Strategic Opportunities

Business Process Redesign. During 2006, we initiated a project to evaluate our business processes and costs against our peers and to redesign those processes where long-term efficiencies could be gained. We identified a number of areas where we could restructure our business to gain efficiencies, including more centralization, an increased focus on process orientation, and more standardized processes. In order to effectively implement these strategies, we are taking steps to redesign our business into the following six core areas to more effectively group and focus resources around our business processes:

- ***Acquire Customers.*** Focuses on the integration of activities involved in acquiring customers, including construction, sales, marketing and operation of our retail appliance center.
- ***Serve Customers.*** Focuses on all aspects of how we serve our customer base, including customer contact, meter reading, account services and field services areas.
- ***Deliver Gas.*** Focuses on the transportation of gas to our customers and includes qualification assurance of our employees, engineering and code compliance.
- ***Energy Supply.*** Focuses on procuring gas, pipeline integrity, gas storage and business development for the future.
- ***Resource Management.*** Focuses on how well we use the resources at our disposal by centralizing dispatch and scheduling, business analysis and technology implementation.
- ***Business Services.*** Focuses on supporting all of the areas above through human resources, information technology, regulation, finance, legal and other administrative functions.

We have begun the implementation of this business model, which is expected to continue over the next several years. Workforce reductions related to the implementation of this new model are expected to be accomplished primarily through attrition and voluntary severance arrangements. In 2006, we incurred costs of $1.9 million related to workforce reductions of approximately 80 employees.

Pipeline Diversity. In September 2006, we announced that we are evaluating a potential pipeline project that would connect TransCanada's Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. We have commenced a process to determine if there is sufficient interest by potential customers to justify construction of the pipeline. If the project is determined to be viable, we would form a partnership with GTN to build and own the pipeline. In addition to owning a share of the pipeline, we would anticipate being a large user of the pipeline and GTN would be its operator. The pipeline would be intended to provide our utility customers and GTN's customers with a more diversified delivery source and greater reliability of gas supplies from the interstate system. The decision on whether to proceed with the development of the pipeline is expected to be made in 2007. No material contractual obligations related to the pipeline have been incurred as of December 31, 2006. If constructed, commercial operation would be expected to commence in 2011.

Earnings and Dividends

Net income was $63.4 million, or $2.29 a diluted share, for the year ended December 31, 2006, compared to $58.1 million, or $2.11 a share, and $50.6 million, or $1.86 a share, for the years ended December 31, 2005 and 2004, respectively. Returns on equity for these three years were 10.7 percent, 10.1 percent and 9.4 percent, respectively.

2006 compared to 2005:

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers due to 3.1 percent customer growth, plus extended coverage from the weather normalization and conservation mechanisms in Oregon, partially offset by weather that was 4 percent warmer than average and 2 percent warmer than 2005 (see "Results of Operations—Comparison of Gas Distribution Operations," below, and "Results of Operations—Regulatory Matters—Rate Mechanisms," below);
- increased margin from regulatory sharing of gas cost savings, from $4.2 million in 2005 to $8.1 million in 2006, partially offset by a $2.7 million temporary unrealized loss related to a derivative contract that will settle and reverse in 2007; and
- increased gas storage margin over the prior year, primarily due to increased storage contract volumes and increased optimization revenue from the independent energy marketing company.

Partially offsetting the above positive factors were:

- increased property tax and depreciation expenses related to increased utility plant in service, which were partially covered by revenue increases approved in the most recent Purchased Gas Adjustment (PGA) filings in Oregon and Washington;

- increased operations and maintenance expense related to higher bonuses tied to improved performance results and to employee severance charges tied to business redesign initiatives, partially offset by lower payroll and employee benefit costs; and
- increased income tax expense related to higher taxable income.

2005 compared to 2004:

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues from sales to residential and commercial customers due to 3.4 percent customer growth, 8 percent colder weather and conservation tariff mechanisms, partially offset by declining average use per customer and a decrease in the contribution from the weather normalization mechanism (see "Results of Operations—Comparison of Gas Distribution Operations," below, and "Results of Operations—Regulatory Matters—Rate Mechanisms," below);
- decreased utility volumes but increased utility margin from industrial customers, primarily reflecting a shift of several customers to higher margin service which offset the overall decline in volumes;
- increased utility margin from miscellaneous revenues; and
- increased gas storage margin primarily due to increased storage services under contract and higher optimization revenues.

Partially offsetting the above positive factors were:

- increased operations and maintenance expense related to increased payroll and employee benefit costs, increased damages to company property, industrial customer settlement charges and employee severance charges;
- increased property tax and depreciation expenses related to increased utility plant in service, which were partially covered by revenue increases approved in the most recent PGA and general rate cases in Oregon and Washington; and
- increased income tax expense related to higher taxable income.

Dividends paid on our common stock were $1.39 a share in 2006, compared to $1.32 a share in 2005 and $1.30 a share in 2004. The current indicated annual dividend rate is $1.42 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (GAAP), management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions.

Our most critical estimates or judgments involve regulatory cost recovery, revenue recognition, derivative instruments, pension assumptions, income taxes and environmental contingencies.

Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Our critical accounting policies and estimates are described below.

Within the context of our critical accounting policies and estimates, management is not currently aware of any reasonably likely events or circumstances that would result in materially different amounts being reported.

Regulatory Accounting

We are regulated by the OPUC and WUTC, which establish our utility rates and rules governing utility services provided to customers, and, to a certain extent, set forth the accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, certain accounting principles, primarily Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," require different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC (see "Results of Operations—Regulatory Matters—Rate Mechanisms," below). There are other expenses or revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. SFAS No. 71 requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these expenses from or refund them to customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of SFAS No. 71, which are applicable to regulated companies, include:

- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

We continue to apply SFAS No. 71 in accounting for our regulated utility operations. Future regulatory changes or changes in the competitive environment could require us to discontinue the application of SFAS No. 71 for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers. Based on current regulatory and competitive conditions, we believe that it is reasonable to expect continued application of SFAS No. 71 for our regulated activities, and that all of our regulatory assets and liabilities at December 31, 2006 and 2005 are recoverable or refundable through future customer rates. See Note 1, "Industry Regulation."

Revenue Recognition

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized when gas is delivered to and received by the customer. Revenues are accrued for gas delivered to customers, but not yet billed, based on estimates of gas deliveries from the last meter reading date to month end (accrued unbilled revenues). Accrued unbilled revenues are primarily based

on a percentage estimate of our unbilled gas each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include total gas receipts and deliveries, customer meter reading dates, customer usage patterns and weather. Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Estimated unbilled revenues at December 31, 2006 and 2005 were $87.5 million and $81.5 million, respectively. The increase in accrued unbilled revenues at year-end 2006 was primarily due to higher gas prices included in customer rates and higher volumes reflecting customer growth. If the estimated percentage of unbilled volume at December 31, 2006 was adjusted up or down by 1 percent, then our unbilled revenues, net operating revenues and net income would have increased or decreased by an estimated $3.4 million, $0.7 million and $0.4 million, respectively.

Non-utility revenues, derived primarily from our gas storage business segment, are recognized upon delivery of the service to customers. Revenues from our optimization partner are recognized over the life of the optimization contract for the guaranteed amount, or are recognized as they are earned for amounts above the guaranteed value based on information provided by the independent energy marketing company.

Accounting for Derivative Instruments and Hedging Activities

Our Financial Derivatives Policy and Gas Acquisition Policy set forth guidelines for using selected financial derivative products to support prudent risk management strategies within designated parameters. These policies specifically prohibit the use of derivatives for trading or speculative purposes. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that qualify as derivative instruments are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to SFAS No. 71 (see Note 1, "Industry Regulation,") and no gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument that is subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "Regulatory Accounting," above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for gains and losses is made in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, collectively referred to as SFAS No. 133 (see Note 1, "Derivatives" and "Industry Regulation"). Our estimate of fair value is determined from period-to-period based on an internal discounted cash flow model using exchange-based forward market prices that are subject to market volatility, except for option contracts where fair value is based on a Black-Scholes model. The estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have a material impact on our results of operations, but the impact would be largely mitigated due to the majority of our derivatives activities being subject to regulatory deferral treatment. For estimated fair values at December 31, 2006 and 2005, see Note 11.

Derivative contracts entered into after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon, with 67 percent of unrealized gains and losses recorded to a regulatory asset or liability account and the remaining 33 percent recognized in current income. The unrealized loss on financial derivative contracts entered into during the fourth quarter of 2006, which was after the 2006 PGA filing, totaled $9.5 million, of which $2.9 million was recorded in cost of gas as of December 31, 2006. This unrealized loss will be reversed in 2007 when the derivative contracts are settled.

The following table summarizes the amount of realized gains and losses from commodity price and currency hedge transactions for the last three years:

Thousands	2006	2005	2004
Net gain (loss) on commodity-price swaps—for utility	$ (18,849)	$ 90,205	$ 44,888
Net loss on commodity-price options—for utility	(1,160)	(1,315)	(2,464)
Subtotal on commodity—for utility	(20,009)	88,890	42,424
Net loss on commodity-price swaps—for gas storage	-	-	(186)
Net gain on foreign currency forward purchases—for utility	355	532	219
Total realized net gain (loss)	$ (19,654)	$ 89,422	$ 42,457

Realized gains (losses) from commodity-price and foreign currency forward purchase contracts are recorded as reductions (increases) to the cost of gas and are included in the calculation of annual PGA rate changes. Unrealized gains and losses resulting from mark-to-market valuations are generally not recognized in current income or other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, which are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 11).

Accounting for Pensions

We maintain two qualified non-contributory defined benefit pension plans covering all regular employees with more than one year of service, several non-qualified supplemental pension plans for eligible executive officers and certain key employees and other employee postretirement benefit plans. Only the two qualified defined benefit pension plans have plan assets, which are held in a qualified trust to fund retirement benefits.

Net periodic pension costs (pension costs) and projected benefit obligations (benefit obligations) are determined in accordance with SFAS No. 87, "Employers' Accounting for Pensions," using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and the expected long-term return on plan assets (see "Financial Condition—Pension Cost and Funding Status," below, and Note 7). These key assumptions have a significant impact on the amounts reported. Pension costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns, which are recognized over a three-year period from the year in which they occur, thereby reducing year-to-year volatility in pension costs.

Effective December 31, 2006, the funded status of our pension plans is required to be recognized in accordance with SFAS No. 158 (see "Employers' Accounting for Defined Benefit Pension and Other Postretirement Benefit Plans" under Note 1, "New Accounting Standards"). SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of our pension plans in accumulated other comprehensive income (AOCI), net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the pension costs relating to certain NW Natural pension plans are recovered in utility rates based on SFAS No. 87, and as such we received regulatory approval from the OPUC to record a regulatory asset or regulatory liability, rather than include AOCI in common equity, for the funded status of those plans pursuant to SFAS No. 71 (see "Regulatory Accounting", above, and Note 1, "Industry Regulation"). As a result of regulatory approval we recognized a $54.4 million regulatory asset for the unfunded status of these qualified pension and other

postretirement benefit plans. If future regulatory changes are to occur that will affect our ability to recover pension costs based on SFAS No. 87, then we would be required to adjust a portion or all of the deferred regulatory asset amount for pension and other postretirement benefit plans. This would cause us to recognize the $33.2 million after-tax charge to common equity and a $21.2 million deferred income tax asset based on the December 31, 2006 funded status, but it would not have an immediate impact on current earnings. Upon adoption of SFAS No. 158, total assets increased $25.7 million, total liabilities increased $26.1 million and equity decreased $0.4 million (see Note 7).

A number of factors are considered in developing pension assumptions, including an evaluation of relevant discount rates, expected long-term investment returns, plan asset allocations, expected changes in salaries, wages and retirement benefits, analyses of current market conditions and input from actuaries and other consultants. For the December 31, 2006 measurement date, we:

- increased the pension discount rate assumptions from 5.75 percent to a range of 6.00 percent to 6.05 percent. The new rate assumptions were determined for each plan based on a matching of the estimated cash flow, which reflects the timing and amount of future benefit payments, to the Citigroup Above Median Curve, which consists of high quality bonds (rated AA- or higher by Standard & Poor's or Aa3 or higher by Moody's Investor Service);
- updated the retirement and withdrawal rates based on a recent study of actual plan experience;
- confirmed the expected rate of future compensation increases between 4.00 and 5.00 percent; and
- confirmed the expected long-term return on plan assets at 8.25 percent.

The benefit obligation at December 31, 2006 decreased $9.3 million due to the increase in the discount rate and increased $0.3 million due to the retirement and withdrawal rates updated for actual experience.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected rate of return assumption, we evaluate an analysis of historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. The actual annualized returns for the past one-year, five-year and 10-year periods ended December 31, 2006 were 14.9 percent, 10.1 percent and 10.2 percent, respectively.

We believe our pension assumptions to be appropriate based on plan design and an assessment of market conditions. However, the following shows the sensitivity of our pension costs and benefit obligations to future changes in certain actuarial assumptions:

Thousands, except percent	Change in Assumption	Impact on 2006 Pension C	Impact on Benefit Obligations at
Discount rate	(0.25%)	$ 884	$ 8,506
Expected long-term return on plan assets	(0.25%)	$ 534	N/A

The impact of a change in pension costs on operating results would be less than the amounts shown above because only between 60 and 70 percent of our pension costs is charged to operations and maintenance expense. The remaining 30 to 40 percent is capitalized to construction accounts as payroll overhead and included in utility plant, which is amortized to expense over the useful life of the asset placed into service.

Accounting for Income Taxes

Income taxes are accounted for in accordance with SFAS No. 109, "Accounting for Income Taxes," by recognizing deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities at current income tax rates.

SFAS No. 109 also requires the recognition of additional deferred income tax assets and liabilities for temporary differences where regulators require us to flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. At December 31, 2006 and 2005, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $67.1 million and $65.8 million, respectively, and recorded an offsetting deferred tax liability for the same amounts (see Note 1, "Income Tax Expense"). We believe that it is reasonable to expect recovery of these regulatory assets through future customer rates. However, future regulatory changes could require the write-off of all or a portion of these regulatory assets should they no longer be probable of recovery in future rates (see "Regulatory Accounting," above, and Notes 1 and 9).

A recent interpretation of SFAS No. 109 (FIN 48), "Accounting for Uncertainty in Income Taxes – an interpretation of Financial Accounting Standards Board (FASB) Statement No. 109," was issued by the FASB in July 2006 to address how companies should account for the tax benefits of timing and permanent income tax positions taken or expected to be taken in a tax return. SFAS No. 109 contains rules which set out how the benefits of tax positions taken or expected to be taken in a tax return are to be reflected in current and deferred income taxes for financial reporting purposes, but it does not establish a confidence level or threshold that must be met in order to recognize a tax benefit in the financial statements. FIN 48 is effective for fiscal years beginning after December 15, 2006, which for us was January 1, 2007.

Adoption of FIN 48 will require us to identify and evaluate all material tax positions taken in previously filed and still open tax returns as well as tax positions expected to be taken in future returns. Each tax position will need to be examined to determine whether the more likely than not recognition standard has been met, and if so, to compute the amount of the tax benefit to be recognized under FIN 48. Based upon a preliminary assessment of the application of FIN 48, the adoption of FIN 48 is not expected to have a material effect on our financial condition, results of operations or cash flows.

Contingencies

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, "Accounting for Contingencies." Estimates of loss contingencies, including estimates of legal defense costs when such costs are probable of being incurred and are reasonably estimable, and related disclosures are updated when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results, developed in consultation with outside counsel and consultants when appropriate. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the low end of the range and disclose the range (see "Contingent Liabilities," below). It is possible, however, that the range of potential liabilities could be

significantly different than amounts currently accrued and disclosed, with the result that our financial condition and results of operations could be materially affected by changes in the assumptions or estimates related to these contingencies.

With respect to our environmental liabilities and related costs, we develop estimates based on currently available information, existing technology and environmental regulations. We previously received regulatory approval to defer and seek recovery of costs related to certain sites and believe the recovery of any costs not recovered under our general liability insurance policies is probable through the regulatory process (see Note 12). In accordance with SFAS No. 71, we recorded a regulatory asset for the amount expected to be recovered. We intend to first pursue recovery for these environmental costs from our general liability insurance policies, which, to the extent successful, would require a corresponding reduction in the regulatory asset. At December 31, 2006, $27.8 million in environmental costs have been recorded as a regulatory asset, including $19.1 million of costs paid to-date and $8.7 million accrued for estimated future environmental costs. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made and could have a material impact on our financial condition or results of operations.

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. In 2006, 93 percent of our utility gas deliveries and 90 percent of our utility operating revenues were derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued growth in the residential and commercial markets and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant.

General Rate Cases

Our most recent general rate increase in Oregon authorized rates to customers based on a return on shareholders' equity (ROE) of 10.2 percent and was effective September 1, 2003. Our most recent general rate case in Washington authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE and was effective July 1, 2004.

In May 2005, we reached a settlement with the staff of the Federal Energy Regulatory Commission (FERC) and all intervenors with respect to our rate case filed in January 2005 related to Mist interstate storage service. The settlement provided for a small net increase in the maximum rates for our interstate storage services, which became effective July 1, 2005. The rates established in this case are designed to reflect updated costs related to investments in the Mist gas storage facility since 2001 and costs associated with the South Mist Pipeline Extension project.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA tariff mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas

commodity purchases, including contractual arrangements to hedge the purchase price with financial derivatives (see "Comparison of Gas Distribution Operations—Cost of Gas Sold," below), interstate pipeline demand charges, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year. Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ from the estimated amounts included in rates, then we are required to defer that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, only 67 percent of the difference is deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

The OPUC and the WUTC approved PGA rate increases on October 25, 2006 that became effective on November 1, 2006. The effect of the PGA rate changes was to increase the average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential sales customers by 2.6 percent. The OPUC also approved a modification to our PGA deferral mechanism, effective November 1, 2006, which provides that we use actual recoveries of gas costs in revenues billed (instead of the prior method that used estimated deliveries for gas costs incorporated in monthly rates) compared to actual purchased gas costs. The new method requires changes in line loss expense to be subject to the PGA deferral mechanism, with 67 percent of any cost differences for Oregon volumes deferred for refund or recovery in customer rates in subsequent periods and the remaining 33 percent included in current earnings. These PGA increases included increased transportation costs (see "Interstate Pipeline Rate Cases," below).

Pursuant to the PGA tariffs, rate increases were approved by the OPUC averaging 15.2 percent for Oregon residential sales customers, and by the WUTC averaging 12.0 percent for Washington residential sales customers, both effective October 1, 2005. In 2004, the OPUC approved a PGA rate increase averaging 20.1 percent for Oregon residential sales customers, and the WUTC approved a PGA rate increase averaging 19.5 percent for Washington residential sales customers, effective October 1 and November 1, 2004, respectively.

The OPUC notified us that they will be conducting a formal review of the PGA process covering gas portfolio requirements, incentive sharing levels and filing requirements, among other items. The investigation is expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected to be effective with the 2008 PGA filing.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a "conservation tariff," which is a rate mechanism designed to adjust margin to compensate the utility for changes in consumption patterns due to residential and commercial customers' conservation efforts. The tariff is a decoupling mechanism that is intended to break the link between earnings and the quantity of energy consumed by customers, removing any incentive to discourage customers' conservation efforts. In Washington, customer use is not covered by a conservation tariff, and as such our utility earnings are affected by increases and decreases in usage based on customers' conservation efforts. Washington customers account for about 10 percent of utility revenues.

In 2005, an independent study to measure the mechanism's effectiveness recommended continuation of the conservation tariff, with minor modifications. In 2005 and 2006, the OPUC approved the continuations of the conservation tariff through September 30, 2009, and increased the

mechanism's coverage from a partial decoupling of 90 percent of residential and commercial gas usage to a full decoupling of 100 percent.

Weather Normalization. In November 2003, the OPUC authorized, and the utility implemented, a weather normalization mechanism in Oregon that helps stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather. The current normalization mechanism is applied to our residential and commercial customers' bills between December 1 and May 15 for each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers (see "Comparison of Gas Distribution Operations," below). We do not have a weather normalization mechanism approved for our Washington customers.

Excess Earnings Test. The OPUC has a formalized process to test for excess utility earnings annually and has confirmed our ability to pass through 100 percent of prudently incurred gas costs into rates. We are authorized to retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates. In 2006 and 2005, the threshold after adjustment was 13.44 percent and 13.32 percent, respectively. No amounts were required to be refunded to customers as a result of the 2005 or 2004 earnings test and we do not expect that any amounts will be required to be refunded to customers as a result of the 2006 earnings test, which will be reviewed by the OPUC during the second quarter of 2007. In Washington, we are not subject to an annual excess earnings test, and 100 percent of all prudently incurred gas costs are passed through into customer rates.

Recent Changes to Industrial Tariffs. In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to acquire to serve this customer group. The parameters include an annual election period, special pricing provisions for out-of-cycle changes and a requirement that customers on our annual weighted average cost of gas tariff complete the term of their service election.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved our applications relating to the accounting treatment and full recovery for the cost of the pipeline integrity management program, as mandated by the Pipeline Safety Improvement Act of 2002 and related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (see "Financial Condition—Cash Flows—Investing Activities," below). We classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period ending June 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA. The accounting and rate treatment for these costs extends through September 30, 2008 and may be reviewed for potential extension after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed for general rate increases with the FERC. Northwest Pipeline

Corporation (Northwest Pipeline) filed for an overall cost of service increase of approximately $119.0 million (a 41 percent increase), including an increase in the firm transportation rate of approximately 45 percent. In connection with this filing, our firm gas transportation rates increased by approximately $17.8 million annually. The major components in the Northwest Pipeline increase relate to a significant capacity replacement project, other capacity displacement projects, an increase in the rate of return and higher operation and maintenance expenses and costs associated with accounting changes to expense pipeline integrity assessment costs. The filed rates and associated tariff sheets became effective on January 1, 2007, subject to refund pending the outcome of further proceedings in the case. In February 2007, Northwest Pipeline filed a settlement proposal with the FERC that would resolve all issues with the active parties and would result in an increase in our transportation rates of about $12.0 million. Amounts collected from our customers in excess of this settlement amount will be deferred and returned to customers in our next PGA rate request in late 2007.

Gas Transmission Northwest's (GTN) rate case proposes, among other things, an increase in firm transportation rates of approximately 71 percent. In connection with this filing, our transportation rates on that pipeline increased by approximately $3.1 million annually. The primary reason for GTN's filing was unsubscribed capacity on the system due to significant capacity turnback and shipper defaults. The filed rates and associated tariff sheets became effective on January 1, 2007, subject to refund pending further proceedings in the case.

Increases in interstate pipeline transportation expenses are subject to our PGA mechanism and are 100 percent passed-through to customers in both Oregon and Washington. Both of the filed general rate increases were reflected in our 2006 PGA filings.

Utility Regulation Legislation

During 2005, the Oregon legislature passed Senate Bill 408 (SB 408) relating to taxes collected by utilities in rates on or after January 1, 2006. SB 408 requires Oregon investor-owned electric and gas utilities to file annual reports and other information with the OPUC. The report is to be filed by October 15 of the year following the reporting year and must identify the amount of income taxes paid, either by the utility or its consolidated group and properly attributed to the utility, as well as the amount of taxes authorized to be collected in rates. If the OPUC determines that the difference between the two amounts is greater than $100,000, the utility is required to establish an "automatic adjustment clause" to adjust rates.

In September 2006, the OPUC issued a final order adopting permanent rules to implement SB 408. The permanent rules established reference points for determining margins and effective tax rates from a utility's ratemaking proceedings. In addition, the OPUC adopted an apportionment methodology for determining taxes properly attributed to the utility from a consolidated tax filing. The OPUC also determined that interest should accrue beginning January 1, 2006, using a mid-year convention for amounts determined under the automatic adjustment clause.

Utilities subject to SB 408 were required to seek a Private Letter Ruling (PLR) from the Internal Revenue Service requesting a ruling as to whether a utility's compliance with the provisions of SB 408 would cause the utility to fail to comply with provisions of federal tax law, including the normalization requirements of the Internal Revenue Code. We submitted our PLR to the Internal Revenue Service in December 2006. While a utility's request for a PLR is pending, no rate adjustment will be implemented. However, interest will begin to accrue on the amount of any rate adjustment determined by the OPUC.

Based on our assessment of the permanent rules, we have estimated that our 2007 Tax Report for the 2006 tax year will reflect a surcharge of approximately $1.6 million; that is, the amount of taxes paid to government entities will exceed the amount of taxes the utility collected in rates, thus creating a rate justment that requires a reimbursement from customers. It is anticipated that any amounts due from customers for the 2006 tax year would not be realized until after June 1, 2008, pending a review by the OPUC. We have determined that the recognition of this regulatory gain in our statement of operations is uncertain until: the OPUC completes its review of how the final rules will be applied to our 2006 financial results; the underlying estimates are finalized; and efforts in the current Oregon legislative session to potentially change certain provisions of SB 408 are completed. Based on our current corporate structure and level of non-utility investments and activities, we do not expect that ongoing compliance with SB 408 will have a material adverse effect on our financial condition, results of operations or cash flows.

Comparison of Gas Distribution Operations

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2006, 2005 and 2004:

Thousands, except degree day and customer data	2006	2005	2004	Favorable/(Unfavorable) 2006 vs. 2005	Favorable/(Unfavorable) 2005 vs. 2004
Utility volumes - therms:					
Residential sales	382,665	371,538	352,356	11,127	19,182
Commercial sales	242,683	233,987	222,875	8,696	11,112
Industrial - firm sales	66,971	74,880	62,843	(7,909)	12,037
Industrial - firm transportation	150,153	135,807	176,978	14,346	(41,171)
Industrial - interruptible sales	112,736	149,106	104,278	(36,370)	44,828
Industrial - interruptible transportation	237,441	192,249	212,536	45,192	(20,287)
Total utility volumes sold and delivered	1,192,649	1,157,567	1,131,866	35,082	25,701
Utility operating revenues - dollars:					
Residential sales	$ 536,468	$ 471,502	$ 383,067	$ 64,966	$ 88,435
Commercial sales	290,666	250,287	200,424	40,379	49,863
Industrial - firm sales	66,986	64,507	45,259	2,479	19,248
Industrial - firm transportation	4,901	4,087	5,035	814	(948)
Industrial - interruptible sales	93,107	100,740	55,380	(7,633)	45,360
Industrial - interruptible transportation	7,899	6,668	7,620	1,231	(952)
Other revenues	161	2,862	4,160	(2,701)	(1,298)
Total utility operating revenues	1,000,188	900,653	700,945	99,535	199,708
Cost of gas sold	648,081	563,772	399,176	(84,309)	(164,596)
Revenue taxes	24,840	21,633	16,865	(3,207)	(4,768)
Utility net operating revenues (margin)	$ 327,267	$ 315,248	$ 284,904	$ 12,019	$ 30,344
Utility margin: [1]					
Residential sales	$ 204,951	$ 195,098	$ 172,209	$ 9,853	$ 22,889
Commercial sales	83,334	78,919	70,565	4,415	8,354
Industrial - sales and transportation	32,383	31,632	31,026	751	606
Miscellaneous revenues	4,333	4,990	3,472	(657)	1,518
Other margin adjustments	2,610	2,950	(1,939)	(340)	4,889
Margin before regulatory adjustments	327,611	313,589	275,333	14,022	38,256
Weather normalization mechanism	2,282	(1,308)	7,873	3,590	(9,181)
Decoupling mechanism	(2,626)	2,967	1,698	(5,593)	1,269
Utility margin	$ 327,267	$ 315,248	$ 284,904	$ 12,019	$ 30,344
Customers - end of period:					
Residential customers	575,116	556,667	537,152	18,449	19,515
Commercial customers	60,523	59,543	58,548	980	995
Industrial customers	945	953	935	(8)	18
Total number of customers - end of period	636,584	617,163	596,635	19,421	20,528
Actual degree days	4,089	4,178	3,853		
Percent colder (warmer) than average [2]	(4%)	(2%)	(10%)		

[1] Amounts reported as margin for each category of customers is net of demand charges and revenue taxes.

[2] Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

Certain amounts in prior years have been reclassified to conform to the current year presentation. These reclassifications had no impact on prior year results of operations.

2006 compared to 2005:

Total utility margin increased $12.0 million or 4 percent in 2006 compared to 2005 with residential and commercial customers contributing an additional $12.3 million to margin in 2006, including weather normalization and decoupling mechanisms. The $0.8 million increase in margin from industrial customers in 2006 was offset by a decrease in revenue adjustments from regulatory deferrals and amortizations and miscellaneous fees. The weather normalization and decoupling mechanisms decreased margin by a net $2.0 million in 2006 compared to 2005, primarily reflecting lower than expected consumption decline due to customer conservation efforts.

Our customer base continued to grow in 2006, with a net increase of 19,421 customers. The growth rate for 2006 was 3.1 percent, compared to 3.4 percent in 2005. The slower growth rate in 2006 was primarily due to a smaller increase in residential customers reflecting a modest slowdown in new construction.

Our utility margin results are affected by customer growth and to a certain extent by changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills and our margin up or down based on above- or below-average temperatures during the winter heating season (see "Results of Operations—Regulatory Developments—Rate Mechanisms," above). Both mechanisms are designed to reduce the volatility of our utility earnings.

In 2006, weather was 2 percent warmer than in 2005. The weather normalization mechanism added $2.3 million to margin for the year ended December 31, 2006 based on weather that was 4 percent warmer than average. The mechanism reduced margin by $1.3 million in 2005 based on weather that was 2 percent warmer than average. Generally, we would have expected the weather normalization mechanism in 2005 to recover lost margin when temperatures were warmer than average, but that year we lost heating volumes and corresponding margin revenues in the latter part of May when temperatures were significantly warmer than average because those volume and margin losses were not entirely covered by the weather normalization mechanism, which ends on May 15 each year.

The decoupling mechanism decreased margin by $2.6 million in 2006, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a contribution of $3.0 million in 2005.

2005 compared to 2004:

Total margin increased $30.3 million or 11 percent in 2005 compared to 2004 with residential and commercial customers contributing an additional $23.3 million to margin, including weather normalization and decoupling mechanisms. Industrial customers contributed an additional $0.6 million to margin, and revenue adjustments for regulatory deferrals and amortizations and miscellaneous fees increased margin by $6.4 million. The weather normalization and decoupling mechanisms adjusted margin down by $7.9 million in 2005 compared to 2004, primarily reflecting the impact of 8 percent colder weather in 2005.

Our customer base increased by 20,528 in 2005 for a growth rate of 3.4 percent, compared to 3.2 percent in 2004.

In 2005, weather was 8 percent colder than in 2004, which partially contributed to the 9 percent increase in margin from residential and commercial sales from those customers not covered by weather normalization. The weather normalization mechanism reduced margin by $1.3 million for the year ended December 31, 05 based on weather that was 2 percent warmer than average but contributed $7.9 million to margin in 2004 based on weather that was 10 percent warmer than verage.

The decoupling mechanism contributed $3.0 million to margin in 2005, after adjusting margin for expected price elasticity in the annual Oregon PGA filing, compared to a contribution of $1.7 million in 2004.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service territory.

2006 compared to 2005:

- volumes sold were 3 percent higher, primarily reflecting 3.1 percent customer growth in the residential and commercial sector and improved economic conditions, partially offset by 2 percent warmer weather;
- operating revenues were 15 percent higher, primarily due to a 3 percent increase in volumes and an 11 percent increase in the average rate per therm due to recent PGA rate increases, effective October 1, 2005 and November 1, 2006; and
- margin was 5 percent higher, reflecting customer growth and higher gas cost savings from our PGA incentive sharing mechanism in Oregon (see "Cost of Gas," below).

2005 compared to 2004:

- volumes sold were 5 percent higher, including unbilled sales, reflecting the impact of 3.4 percent customer growth and 8 percent colder weather partially offset by declining average consumption due to customer conservation;
- operating revenues were 24 percent higher, primarily due to a 5 percent increase in volumes and an 18 percent increase in the average rate per therm due to the PGA rate increases, effective October 1, 2004 and 2005; and,
- margin was 13 percent higher reflecting customer growth and increases in gas cost savings from our PGA incentive sharing mechanism in Oregon (see "Cost of Gas," below).

Typically, 80 percent or more of annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced with the weather normalization mechanism in Oregon (see "Regulatory Matters—Rate Mechanisms," above). Beginning in 2006, this mechanism is effective from December 1 through May 15 of each heating season. Approximately 10 percent of our residential and commercial customers are in Washington, where the mechanism is not in effect, and about 9 percent of our eligible Oregon customers have voluntarily elected not to be covered by the mechanism, so the mechanism does not fully insulate us from earnings volatility due to weather. The mechanism increased margin by a net $2.3 million in the twelve-month period ended December 31, 2006, decreased margin by $1.3 million in 2005 and increased margin by $7.9 million in 2004.

Industrial Sales and Transportation

The primary factors that impact results of operations in the industrial sales and transportation markets are commodity costs, competitive factors in the energy industry and economic conditions in our service territory.

2006 compared to 2005:

- volumes delivered to industrial customers increased 15.3 million therms, or 2.8 percent, with the increase primarily in lower margin interruptible schedules;
- operating revenue decreased $3.1 million, or 1.8 percent, due to customers transferring from sales service to transportation service where cost of gas is not a component in operating revenues; and
- margin increased 2 percent, reflecting increased volumes.

2005 compared to 2004:

- volumes delivered to industrial customers decreased 4.6 million therms, or less than 1.0 percent;
- operating revenue increased $62.7 million, or 55 percent, reflecting a 34 percent increase in sales volumes due to customers that migrated from transportation to sales service where the cost of gas component is included in revenues and to rate increases effective October 1, 2004 and 2005; and
- margin increased 2 percent due to the migration of customers to higher margin rate schedules, partially offset by lower volumes.

Several large industrial customers transferred from sales service back to transportation service in 2006. In 2005, high natural gas prices resulted in a number of our large industrial customers switching from transportation service, where they arrange for their own supplies through independent third parties, to sales service where we sell them the gas commodity under regulatory tariffs. Our tariff requires us to charge the incremental cost of gas supply incurred to serve those customers.

Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferrals relating to gas costs. Other revenues increased net operating revenues by $0.2 million in 2006, compared to $2.9 million in 2005 and $4.2 million in 2004.

2006 compared to 2005:

Other revenues in 2006 were $2.7 million lower than in 2005 primarily due a $5.6 million decrease in deferrals under the decoupling mechanism (see "Regulatory Matters—Rate Mechanisms," above) and a $1.5 million increase in amortization of the decoupling deferrals from prior periods, partially offset by an increase of $1.3 million in interstate gas storage credits to customers reflecting increased net income from storage operations, a decrease of $1.7 million in amortization expense for the South Mist Pipeline Extension and a decrease of $1.0 million in the deferral for the Oregon income tax kicker refund.

2005 compared to 2004:

In 2005, other revenues were $1.3 million lower than in 2004 primarily due to a $2.6 million decrease in interstate gas storage credits to customers resulting from lower net income from storage operations and the deferral of $1.0 million for the Oregon income tax kicker refund, partially offset by a $1.1 million increase in customer late payment fees and a special enhanced service contract and a $1.3 million increase in deferrals under the decoupling mechanism (see "Regulatory Matters—Rate Mechanisms," above).

Cost of Gas Sold

Natural gas commodity prices have risen significantly in recent years. The effects of higher commodity prices and price volatility on core utility customers are mitigated, in part, through our use of underground storage facilities, fixed-price commodity hedge contracts and short term sales of excess gas supply and transportation capacity to off-system customers in periods when core utility customers do not require the full amount of contract gas supplies or firm pipeline capacity.

The total cost of gas sold was $648.1 million in 2006, an increase of $84.3 million or 15 percent compared to 2005, and cost of gas sold in 2005 was $563.8 million, an increase of $164.6 million or 41 percent higher than 2004. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains or losses from commodity hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Under the PGA tariff in Oregon, our net income is affected within defined limits by changes in purchased gas costs (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). In each of the last three years, our actual gas costs were lower than the gas costs embedded in rates, with the effect that our share of the cost savings increased margin by $8.1 million, $4.2 million and $0.6 million for 2006, 2005 and 2004, respectively.

We use a natural gas commodity-price hedge program under the terms of our Financial Derivatives Policy to help manage our exposure to floating price gas purchase contracts (see "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," above, and Note 11). We realized net losses of $20.0 million from our financial hedges in 2006, compared to gains of $88.9 million and $42.4 million in 2005 and 2004, respectively. Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, which are factored into our PGA deferrals and annual rate changes, but to the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism with 67 percent deferred and 33 percent recorded to current income.

Business Segments Other than Local Gas Distribution

Gas Storage

We earned $6.0 million in net income from our non-utility gas storage business segment in 2006, after regulatory sharing and income taxes, equivalent to cents a share, compared to $4.6 million or 17 cents a share in 2005 and $2.9 million or 11 cents a share in 2004 (see Note 2). Earnings from this business segment were higher in 2006 primarily because of increased net revenues

from interstate storage service contracts and our contract with an independent energy marketing company that optimizes the value of our utility assets.

In Oregon, we retain 80 percent of the pre-tax income from gas storage as well as from third party optimization revenues when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such storage and optimization when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from storage services and third party optimization.

Other

Net income from our other non-regulated investment activities was $0.8 million in both 2006 and 2005 and $0.6 million in 2004. In 2006, we recognized net income of $0.2 million from Financial Corporation, and we completed the sale of a non-utility real estate investment that contributed a $0.3 million gain, before tax. Also in 2006, we recognized an additional $0.2 million from a real estate transaction where the property was sold on an installment basis, and we reclassified our investment in a Boeing 737-300 aircraft to current assets due to the lease term expiration in 2007 and our expectation that the asset will be sold prior to year end.

Subsidiaries

Financial Corporation

Operating results in 2006 were net income of $0.2 million, compared to $0.3 million in 2005 and $0.2 million in 2004. Our investment in Financial Corporation was $2.6 million at December 31, 2006, compared to $3.1 million at December 31, 2005.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses increased by $1.3 million in 2006, or 1 percent, compared to 2005 and increased $11.1 million, or 11 percent, in 2005 compared to 2004. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2006 compared to 2005:

- a $2.0 million increase in payroll expense, primarily due to bonuses related to improved results on annual performance goals and an increase in the long-term incentive plan liability due to a higher total shareholder return than our peer group average on which the award is based;
- a $1.1 million increase in severance expenses related to the 2006 severance incentive plan; and
- a $0.8 million increase in stock option expense due to the required adoption of SFAS No. 123R related to stock-based compensation expense (see Note 4).

Partially offsetting the above increases were:

- a $1.2 million decrease in system damages and damage claims written-off; and
- a $2.3 million reduction in charges related to a settlement with a group of industrial customers in 2005.

2005 compared to 2004:

- a $3.0 million increase in regular payroll-related expense resulting from employee additions, pay increases and higher benefit costs;
- a $2.3 million increase in bonus payroll expense related to improved results on performance goals and an increase in the accrued long-term incentive plan liability due to a higher stock price on which the award is based;
- a $2.0 million charge related to a settlement with a group of industrial customers;
- a $1.0 million increase in system damages and damage claims written-off;
- a $0.9 million increase related to employee severance charges;
- a $0.4 million increase in costs for software maintenance; and
- a $0.4 million increase in costs for consumer safety advertising.

Partially offsetting the above increases was:

- a $0.3 million decrease in uncollectible accounts expense reflecting improved collection results and cash recoveries of accounts previously written-off.

Some of the cost increases we experienced in 2005 over 2004 were included in the rates approved in our general rate cases in Oregon and Washington (see "Regulatory Matters—General Rate Cases," above).

General Taxes

General taxes, which are principally comprised of property and payroll taxes, increased $1.2 million, or 5 percent, in 2006 compared to 2005, and increased $1.2 million, or 6 percent, in 2005 compared to 2004.

Payroll taxes decreased $0.1 million in 2006 compared to 2005 and decreased $0.5 million in 2005 compared to 2004. In 2004, payroll taxes included an accrual for taxes on the 2004 bonuses paid in 2005.

Property taxes increased $0.7 million in 2006 and $1.5 million in 2005 primarily due to increased utility plant in service.

Regulatory fees increased by $0.5 million or 28 percent in 2006 compared to 2005 due to higher utility operating revenues. Increases in regulatory fees are generally recovered on a timely basis through an increase in customer rates through the annual PGA filing.

Depreciation and Amortization

The following table summarizes the increases in total plant and property and total depreciation and amortization for the three years ended December 31:

Thousands	2006	2005	2004
Plant and property:			
Utility plant:			
Depreciable	$ 1,925,837	$ 1,839,206	$ 1,768,630
Non-depreciable, including construction work in progress	37,661	36,238	26,342
	1,963,498	1,875,444	1,794,972
Non-utility property:			
Depreciable	36,952	36,920	27,109
Non-depreciable, including construction work in progress	5,700	3,916	6,854
	42,652	40,836	33,963
Total plant and property	$ 2,006,150	$ 1,916,280	$ 1,828,935
Depreciation and amortization:			
Utility plant	$ 63,552	$ 60,935	$ 56,899
Non-utility property	883	710	472
Total depreciation and amortization expense	$ 64,435	$ 61,645	$ 57,371
Average depreciation rate - utility	3.4%	3.4%	3.4%
Average depreciation rate - non-utility	2.5%	2.6%	2.3%

Total depreciation and amortization expense increased by $2.8 million, or 5 percent, in 2006 and by $4.3 million, or 7 percent, in 2005. The increased expense for both years is primarily due to additional investments in utility plant to meet continuing customer growth and to make system improvements (see "Financial Condition—Cash Flows—Investing Activities," below, and Note 9). We recently completed a depreciation study on all company plant and property, which generally indicates that depreciation rates overall would be reduced if we maintain the existing average service life depreciation method. However, if the OPUC were to adopt a different depreciation method such as the equal life group method, then depreciation rates could increase. Utility depreciation rates and methods are subject to review and approval by the OPUC and WUTC, and new rates will not be placed into service until depreciation rate proceedings are approved. We intend to submit the depreciation study for regulatory approval in 2007 and implement the new rates upon approval. We do not anticipate that adoption of these new rates will have a material impact on our financial condition or results of operations.

Other Income and Expense—Net

The following table provides details on other income and expense – net for the last three years:

Thousands	2006	2005	2004
Gains from company-owned life insurance	$ 2,609	$ 1,856	$ 2,855
Allowance for funds used during construction - equity	-	-	708
Interest income	363	403	232
Other non-operating expenses	(852)	(1,393)	(1,222)
Net interest on deferred regulatory accounts	(177)	282	74
Earnings from equity investments of Financial Corporation	191	57	181
Total other income	$ 2,134	$ 1,205	$ 2,828

Other income and expense–net improved by $0.9 million in 2006 over 2005. The increase was primarily due to higher gains of $0.8 million from company-owned life insurance, reflecting higher policy benefits realized during 2006, and a net decrease of $0.5 million in other non-operating expenses, reflecting cost reduction initiatives. These positive changes were partially offset by a $0.5 million increase in net interest charges on deferred regulatory accounts, reflecting higher net credit balances outstanding in these accounts.

Other income and expense–net was $1.6 million lower in 2005 compared to 2004. The decrease was primarily due to $1.0 million lower gains from company-owned life insurance, reflecting the liquidation of $17.6 million in cash surrender value of policies in 2004, and the absence of the equity component in the allowance for funds used during construction (AFUDC) reflecting lower construction work in progress balances.

Interest Charges–Net of Amounts Capitalized

Interest charges–net of amounts capitalized in 2006 was $2.0 million, or 5 percent, higher than in 2005, reflecting higher interest rates on short-term debt balances and slightly higher average balances of long-term debt outstanding during the period due to the issuance of $50 million in June 2005 and $25 million in December 2006. AFUDC reduced interest expense by $0.8 million in 2006, compared to reductions of $0.5 million in 2005 and $1.0 million in 2004. The increase in AFUDC in 2006 reflects higher construction work in progress balances. The decrease in AFUDC in 2005 reflects lower balances due to the completion in 2004 of our major South Mist Pipeline Extension project, which extended the pipeline from our Mist gas storage field to serve growing portions of our service area. The average interest crediting rate for AFUDC, comprised of short-term and long-term borrowing rates, as appropriate, was 4.7 percent in 2006, 3.1 percent in 2005 and 3.0 percent in 2004.

Income Tax Expense

Income tax expense totaled $36.2 million in 2006 compared to $32.7 million in 2005. The effective tax rate was 36.4 percent in 2006 compared to 36.0 percent in 2005. The higher 2006 effective tax rate partially reflects the expiration of a federal tax credit associated with Financial Corporation's investment in a low-income housing project (see Note 2, "Other") and non-taxable life insurance gains. Income tax expense increased by $6.2 million in 2005, as compared to total income tax expense of $26.5 million in 2004, and the effective tax rate increased 1.6 percent from an effective tax rate of 34.4 percent in 2004. The higher 2005 effective tax rate was primarily attributable to a decrease in tax benefits of $0.8 million resulting from a non-taxable gain on company-owned life insurance in 2004 and from $0.7 million in other tax adjustments recorded in 2004.

A recent interpretation (FIN 48) of SFAS No. 109, "Accounting for Uncertainty in Income taxes—an interpretation of FASB Statement No. 109," was issued by the FASB in July 2006 to address how companies should account for the tax benefits of timing and permanent income tax positions taken or expected to be taken in a tax return. See "Application of Critical Accounting Policies and Estimates—Accounting for Income Taxes," above and Note 1, "Recent Accounting Pronouncements."

Financial Condition

Capital Structure

Our goal is to maintain a target capital structure comprised of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources also are used to meet long-term debt redemption requirements and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Notes 3, 5 and 6). Our consolidated capital structure was as follows:

December 31,	2006	2005
Common stock equity	48.1%	47.2%
Long-term debt	41.5%	42.0%
Short-term debt, including current maturities of long-term debt	10.4%	10.8%
Total	100.0%	100.0%

Achieving the target capital structure and maintaining sufficient liquidity are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs.

Liquidity and Capital Resources

At December 31, 2006, we had $5.8 million in cash and cash equivalents compared to $7.1 million at December 31, 2005. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed bank lines of credit. We have available committed bank lines totaling $200 million with five commercial banks through September 30, 2010 (see "Lines of Credit," below, and Note 6). Short-term debt balances typically are reduced toward the end of the winter heating season as a significant amount of our current assets, primarily accounts receivable and gas inventories, are converted into cash.

Capital expenditures primarily relate to utility construction resulting from customer growth and system improvements (see "Cash Flows—Investing Activities," below). Certain contractual commitments under capital leases, operating leases, gas supply purchase contracts and other contracts require an adequate source of funding. These capital and contractual expenditures are financed through cash from operations and from the issuance of short-term debt, which is periodically refinanced through the sale of long-term debt or equity securities.

To provide long-term financing, we periodically issue and sell secured or unsecured debt, preferred stock or common stock. In April 2004, we issued $40 million of common stock and in June 2005 and December 2006, we issued $50 million and $25 million of secured medium-term notes, respectively. At December 31, 2006, we had $85 million available for future issuance of debt or equity securities under a universal shelf registration, which was previously approved by the OPUC (see "Financing Activities," below).

Neither our Mortgage and Deed of Trust nor the Indenture under which other long-term debt may be issued contain credit rating triggers or stock price provisions that require the acceleration of debt repayment. Also, there are no rating triggers or stock price provisions contained in contracts or other agreements with third parties, except for agreements with certain counterparties under our Financial Derivatives Policy, which may require the affected party to provide substitute collateral such as cash, guaranty or letters of credit if credit ratings are lowered to non-investment grade, or in some cases if the mark-to-market value exceeds a certain threshold.

Based on the availability of short-term credit facilities and our expectation of being able to issue long-term debt and equity securities, we believe there is sufficient liquidity to satisfy our anticipated cash requirements, including the contractual obligations and investing and financing activities discussed below.

Dividend Policy

We have paid quarterly dividends on our common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments have increased each year since 1956. The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. It is the intention of the Board of Directors to continue to pay cash dividends on common stock on a quarterly basis. However, the declarations and amounts of future dividends will be dependent upon our earnings, cash flows, financial condition and other factors.

Off-Balance Sheet Arrangements

Except for certain lease and purchase commitments (see "Contractual Obligations," below), we have no material off-balance sheet financing arrangements.

Contractual Obligations

The following table shows our contractual obligations by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2007	2008	2009	2010	2011	Thereafter	Total
Commercial paper	$ 100,100	$ -	$ -	$ -	$ -	$ -	$ 100,100
Long-term debt maturities	29,500	5,000	-	35,000	10,000	467,000	546,500
Interest on long-term debt	34,396	33,632	33,417	33,406	30,858	341,592	507,301
Pension funding obligation	13,139	13,818	14,513	15,615	16,221	93,212	166,518
Postretirement funding obligation	1,571	1,596	1,626	1,685	1,753	9,002	17,233
Capital leases	317	233	84	-	-	-	634
Operating leases	4,200	4,100	4,100	4,100	4,100	35,300	55,900
Gas purchase contracts[1]	283,180	177,943	98,807	47,263	25,828	73,179	706,200
Gas pipeline commitments	81,024	70,848	64,988	66,085	70,059	198,863	551,867
Other purchase commitments	15,121	57	-	-	-	-	15,178
Total	$ 562,548	$ 307,227	$ 217,535	$ 203,154	$ 158,819	$ 1,218,148	$ 2,667,431

[1] All gas purchase contract use price formulas tied to monthly index prices. Commitment amounts are based on index prices at December 31, 2006.

Other purchase commitments primarily consist of remaining balances under existing purchase orders. These and other contractual obligations are financed through cash from operations and from the issuance of short-term debt, which is periodically refinanced through the sale of long-term debt or equity securities.

Holders of certain long-term debt have put options that, if exercised, would require repurchases of up to $20 million principal amount in each of 2007, 2008 and 2009. If repurchased prior to maturity, then the interest obligation shown in the above table would be reduced in future years. The interest rate on the long-term debt issues with put options ranges between 6.52 percent and 7.05 percent.

In March 2004, our employees who are members of the Office and Professional Employees International Union, Local No. 11, approved a labor agreement (Joint Accord) covering wages, benefits and working conditions. This contract will expire on May 31, 2009.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may also be used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by committed bank lines of credit (see "Lines of Credit," below). We had $100.1 million in commercial paper notes outstanding at December 31, 2006, compared to $126.7 million at December 31, 2005.

Lines of Credit

In September 2005, we entered into agreements for unsecured lines of credit totaling $200 million with five commercial banks, replacing the former $150 million credit facilities. The bank lines of credit are available and committed for a term of five years from October 1, 2005 to September 30, 2010. Our bank lines are used primarily as back-up support for the notes payable under our commercial paper borrowing program. Commercial paper provides the liquidity to meet our working capital and external financing requirements.

Under the terms of these bank lines, we pay upfront fees and annual commitment fees but are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under these bank lines are based on then-current market interest rates. All principal and unpaid interest under the bank lines is due and payable on September 30, 2010.

The bank lines require that we maintain credit ratings with Standard & Poor's Rating Services (S&P) and Moody's Investors Service (Moody's) and notify the banks of any change in our senior unsecured debt ratings by such rating agencies. A change in our credit rating is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition of drawing upon the bank lines. However, interest rates on any loans outstanding under these bank lines are tied to our credit ratings, which would increase or decrease the cost of any loans under the bank lines when ratings are changed.

The bank lines also require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2006 and 2005.

Credit Ratings

The table below summarizes our credit ratings from two rating agencies, S&P and Moody's.

	S&P	Moody's
Commercial paper (short-term debt)	A-1+	P-1
Senior secured (long-term debt)	AA-	A2
Senior unsecured (long-term debt)	A+	A3
Ratings outlook	Stable	Stable

On February 28, 2006, S&P raised the credit ratings on our senior secured long-term debt to "AA-" from "A+" and our senior unsecured long-term debt to "A+" from "A." S&P also raised the credit ratings on commercial paper to "A-1+" from "A-1." Both of the rating agencies have assigned us an investment grade rating. These credit ratings and ratings outlook are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

In August 2006, we elected to discontinue the credit rating service from Fitch Ratings (Fitch) for cost management reasons. At the time this service was cancelled, Fitch had assigned an A+ rating to our secured long-term debt, an A rating to our unsecured long-term debt and an F1 rating to our commercial paper program. Also, the ratings outlook from Fitch was stable.

Redemptions of Long-Term Debt

In June 2006, we redeemed $8.0 million of secured 6.05% Series B Medium-Term Notes (MTNs) at maturity.

In July 2005, we redeemed three series of maturing secured MTNs aggregating $15 million in principal amount. The series redeemed were the 6.34% Series B, the 6.38% Series B and the 6.45% Series B, each due in July 2005. The notes were redeemed with proceeds from the sales of $50 million in principal amount of secured MTNs in June 2005 (see "Cash Flows—Financing Activities," below).

In August 2005, we called for redemption all of our outstanding Convertible Debentures, 7-1/4% Series due 2012, at 100 percent of their principal amount plus accrued interest to the date of redemption. During 2005, debentures with an aggregate principal amount of $4.0 million were converted into shares of common stock on or prior to the redemption date at the rate of 50.25 shares for each $1,000 principal amount of debentures and $0.5 million of debentures were redeemed.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In 2006, our cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $44.6 million, primarily due to a $31.0 million decrease in cash contributions to our qualified defined benefit pension plans and a $18.2 million increase in cash collections from deferred gas costs and improved operating results, partially offset by a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus

depreciation. In 2005, the cash flow from net income and operating activity adjustments, excluding working capital changes, decreased by $25.9 million, primarily due to a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation and an increase in cash contributions to our qualified pension plans, partially offset by an increase in net income and cash from deferred gas costs.

The overall change in cash flow from operating activities in 2006 compared to 2005 was an increase of $69.5 million. The overall change in cash flow from operations was a decrease of $25.8 million in 2005 compared to 2004. The significant factors contributing to the cash flow changes between years are as follows:

2006 compared to 2005:

- an increase in net income added $5.3 million to cash flow;
- a decrease in cash of $26.0 million related to a deferred income tax benefit in 2006 compared to a deferred income tax expense in 2005;
- the change to regulatory liabilities in 2006 from regulatory receivables in 2005 related to deferred gas costs increased cash flow by $18.2 million, reflecting deferral activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- cash increased by $31.0 million in 2006 compared to 2005 due to the 2005 cash contributions to our qualified defined benefit pension plans;
- an increase in cash in 2006 of $36.5 million due to a decrease in accounts receivable and accrued unbilled revenue related to warmer weather around year end;
- an increase of $27.7 million in cash resulting primarily from a decrease in gas inventory costs in 2006 compared to 2005;
- a decrease in income taxes receivable contributed $10.5 million to cash in 2006;
- a reduction in accounts payable decreased cash $54.5 million in 2006 primarily due to lower gas prices around year end;
- a reduction in prepayments increased cash $6.4 million in 2006; and
- an increase in deferred regulatory liabilities increased cash by $11.3 million in 2006.

2005 compared to 2004:

- an increase in net income added $7.6 million to cash flow;
- a decrease in deferred income tax expense in 2005, compared to a significant increase in 2004, decreased cash by $27.2 million, reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation;
- a small decrease in regulatory receivables in 2005, compared to a large increase in 2004 for deferred gas costs, increased cash flow by $17.8 million, reflecting deferral activity, including collections, between the two years with respect to purchase gas cost savings and off-system gas sales under our PGA tariff;
- cash contributions to our qualified defined benefit pension plan decreased cash flows by $22.7 million, primarily due to a $31.0 million pension contribution to those plans in 2005, compared to $8.3 million in 2004;
- an increase in deferred environmental costs decreased cash flow by $6.9 million, reflecting an increase in cash requirements for environmental remediation work during 2005 (see "Contingent Liabilities—Environmental Matters," below);

- a larger increase in accounts receivable reduced cash flow by $11.6 million, primarily reflecting the higher gas prices and the timing of customer account collections;
- a larger increase in accrued unbilled revenue reduced cash flow by $11.8 million, reflecting a combination of higher gas prices and colder weather in December 2005 compared to December 2004;
- an increase in inventories decreased cash flow by $4.1 million, primarily reflecting injections into storage at higher gas prices;
- a decrease in income taxes receivable increased cash flow by $9.7 million; and
- an increase in accounts payable increased cash flow by $16.4 million, primarily reflecting higher gas prices at year-end 2005.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations (see "Liquidity and Capital Resources—Contractual Obligations," above, and Note 12).

Investing Activities

Cash requirements for investing activities in 2006 totaled $90.6 million, down slightly from $92.0 million in 2005. Cash requirements for the acquisition and construction of utility plant totaled $95.3 million in 2006, up from $89.3 million in 2005. The increase in cash requirements for utility construction in 2006 primarily reflects $12.5 million of capital expenditures in 2006 for an automated meter reading system, which will be completed in 2007.

Cash requirements for investing activities in 2005 totaled $92.0 million, down from $132.6 million in 2004. Cash requirements for the acquisition and construction of utility plant totaled $89.3 million, down from $138.3 million in 2004. The decrease in cash requirements for utility construction in 2005 reflects the completion in 2004 of our South Mist Pipeline Extension project, which extended the pipeline from our Mist gas storage field to serve growing portions of our service area. The total cost of the project was approximately $108.0 million, which includes amounts reflected in investing activities primarily over the 2002-2004 period. The cost of service associated with the final phase of the project, net of deferred tax benefits, was included in utility customer rates beginning in the fourth quarter of 2004.

Investments in our pipeline integrity management program were $11.0 million in 2006, compared to $6.1 million in 2005 and $1.6 million in 2004. These costs are estimated at approximately $50 million to $100 million over a ten-year period through 2012. The costs are accumulated over each 12-month period ending September 30, and the capitalized costs, subject to audit, are recovered through the annual PGA based on adjustments to rate base each year. The approved regulatory accounting and rate treatment for these costs extends through September 30, 2008, and may be reviewed for potential extension after that date.

Investments in non-utility property totaled $1.8 million in 2006, compared to $6.8 million in 2005 and $10.6 million in 2004. The lower investments in both 2006 and 2005 compared to 2004 were primarily due to the completion of expansion projects at our gas storage facilities in 2004 and partially in 2005.

In 2006, we received proceeds from the settlement of company-owned life insurance policy benefits totaling $4.0 million compared to $0.3 million in 2005. In 2004, we received proceeds from the surrender of certain life insurance policies as well as from policy benefit distributions totaling $17.6 million.

During the five-year period 2007 through 2011, utility construction expenditures are estimated at between $500 and $600 million. The estimated level of capital expenditures over the next five years reflects continued customer growth, gas storage development, technology improvements and utility system improvements, including requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds are expected to be internally generated over the five-year period and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

Our utility and non-utility capital expenditures for 2007 are estimated to total $110 million, including $27 million for customer growth, $21 million for system improvements, $13 million for equipment, facilities and information technology, $10 million for pipeline integrity costs, $5 million for an automated meter reading project, $14 million for utility and non-utility gas storage, and $20 million for construction overhead. These estimates do not include costs of the potential pipeline project with GTN or other investments that may be driven by our business process redesign (see "Strategic Opportunities," above).

In December 2003, the U.S. Department of Transportation's Office of Pipeline Safety (now the Pipeline Hazardous Materials Safety Administration) issued a rule that specifies the detailed requirements for transmission pipeline integrity management plans as mandated by the Pipeline Safety Act. See Part I., Item 1., "Pipeline Safety." We have met the first major milestones required by the Act and are on track to complete the next milestone, inspection of the highest risk 50 percent of our transmission pipelines, by the end of 2007.

Financing Activities

Cash used in financing activities in 2006 totaled $59.4 million, as compared to cash provided by financing in 2005 of $14.8 million. Factors contributing to the $74.2 million net change were the net change in short-term debt ($50.8 million), a lower amount of long-term debt issued during 2006 ($25.0 million) and the lower amount of equity financing in 2006 ($3.6 million), partially offset by a smaller redemption of long-term debt in 2006 compared to 2005 ($7.5 million).

Cash provided by financing activities in 2005 totaled $14.8 million, compared to $28.3 million in 2004. Factors contributing to the $13.4 million decrease were the redemption of long-term debt and convertible debentures ($15.5 million), the increased repurchases of common stock in 2005 ($14.4 million) and the lower amount of equity financing in 2005 ($39.1 million), partially offset by the issuance of $50 million of secured MTNs during 2005 and the net change in short-term debt ($6.9 million).

In December 2006, we sold $25 million of 5.15% Series B, secured MTNs due 2016 and used the proceeds to reduce short-term indebtedness and to fund utility construction.

In 2005, we sold $40 million of 4.70% Series B, secured MTNs due 2015 and $10 million of 5.25% Series B, secured MTNs due 2035, and used the proceeds to redeem long-term debt, to reduce short-term indebtedness and to make investments in utility plant.

In April 2004, we issued and sold 1,290,000 shares of our common stock in an underwritten public offering, and used the net proceeds of $38.5 million to reduce short-term indebtedness and to fund, in part, our utility construction program.

In 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program, and in 2006 that program was modified to 2.6 million shares and $85 million in value and extended through May 2007. The purchases are made in the open market or through privately negotiated transactions. Repurchases pursuant to the program in 2006 totaled 395,500 shares or $16.0 million and in 2005 were 410,200 shares, or $14.9 million. No shares were purchased pursuant to the program in 2004. Since the program's inception, we have repurchased 1,161,100 shares of common stock at a total cost of $39.1 million (see Part II, Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities," above).

In 2006, we produced free cash flow of $19.7 million, compared to 2005 and 2004 when we had negative free cash flows of $49.3 million and $62.8 million, respectively. Free cash flow is the amount of cash left over after the payment of all cash expenses, capital expenditures (investment activities) and dividends. Free cash flow is a non-GAAP financial measure, but we believe this supplemental information enables the reader of the financial statements to better understand our cash generating ability and to benefit from seeing cash flow results from management's perspective in addition to the traditional GAAP presentation. We monitor free cash flow as one measure of our return on investments. Provided below is a reconciliation from cash provided by operations (GAAP basis) to our non-GAAP free cash flow.

Thousands (year ended December 31)	2006	2005	2004
Cash provided by operating activities	$ 148,566	$ 79,066	$ 104,899
Cash used in investing activities	(90,567)	(92,008)	(132,631)
Cash divided payments on common stock	(38,298)	(36,376)	(35,105)
Free cash flow	$ 19,701	$ (49,318)	$ (62,837)

The free cash flow information presented above is not intended to be a substitute for, nor is it meant to be a better measure of, cash flow results prepared in accordance with GAAP. In addition, the non-GAAP measure we provide may be calculated differently by other companies that present a similar non-GAAP financial measure for free cash flow.

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with SFAS No. 87, "Employers' Accounting for Pensions" (see "Application of Critical Accounting Policies—Accounting for Pensions," above). Pension costs are allocated between operations and maintenance expense and capital accounts based on employee payroll distributions.

Pension costs for our two qualified defined benefit pension plans totaled $8.2 million in 2006, an increase of $1.3 million over 2005. The increase in 2006 pension costs was primarily due to the lower discount rate (5.75 percent in 2006 compared to 6.00 percent in 2005) and the adoption of new mortality rate assumptions of December 31, 2005.

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Generally, it is our policy to contribute at least the minimum amount required by Internal Revenue Code regulations and the Employee Retirement Income Security Act of 1974. It is also our intent to contribute additional

amounts sufficient on a sound actuarial basis to maintain funding targets and provide for the payment of future benefits under the plans.

During 2005, we contributed $31 million to our two qualified defined benefit plans, but no additional contributions were made to these plans in 2006. Although we were not required to make cash contributions in either 2005 or 2006 based on minimum funding requirements, we contributed to these plans in 2005 to maintain a target funding level based on plan benefit obligations.

The fair market value of the assets in these two plans increased to $236.5 million at December 31, 2006, up from $218.6 million at December 31, 2005. The increase included $31.5 million in investment gains, which were offset in part by $12.1 million in withdrawals to pay benefits and $1.4 million in eligible expenses of the two plans. The present value of benefit obligations under the two plans increased from $254 million at December 31, 2005 to $255 million at December 31, 2006. The two qualified defined benefit pension plans were underfunded in aggregate by approximately $18.9 million at December 31, 2006.

Pension costs for the plans totaled $6.9 million in 2005, compared to $6.6 million in 2004. The increase in pension costs in 2005 was primarily due to the lower discount rate (6.00 percent in 2005 compared to 6.25 percent in 2004), partially offset by higher earnings on additional cash contributions to the plans.

At December 31, 2005, the fair market value of the qualified defined benefit pension plans' assets totaled $219 million, up from $187 million at December 31, 2004. The increase included $13.5 million in investment gains and employer contributions of $31 million, which were offset in part by $11.8 million in withdrawals to pay benefits and $0.9 million in eligible expenses of the two plans. The present value of benefit obligations under the two plans increased from $209 million to $254 million during 2005, primarily due to the adoption of a new mortality table to reflect the increased life expectancies of plan participants. The two plans were underfunded in aggregate by about $36 million at December 31, 2005.

Despite the increase in pension costs and the current underfunded status of the plans, we believe the plans to be adequately funded and that we will be able to continue to maintain appropriate funding levels. The annualized returns for the past one, five and 10 years ended December 31, 2006 were 14.9 percent, 10.1 percent and 10.2 percent, respectively. We do not expect our current or future cash contribution requirements to the two plans to have a material adverse effect on our liquidity or financial condition (see Note 7). Effective January 1, 2007, we closed our Non-Bargaining Unit Plan to newly-hired or rehired employees.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2006, 2005 and 2004, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.40, 3.32 and 3.02, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, "Accounting for Contingencies," (see "Application of Critical Accounting Policies and Estimates—Contingencies," above). At December 31, 2006, a cumulative $27.8 million in environmental costs was recorded as a regulatory asset, including $19.1 million of costs paid to-date and $8.7 million of estimated accrued future environmental costs. If it is determined that both the insurance recovery and future customer rate recovery of such costs is not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 12.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, weather risk and interest rate risk. The following describes our exposure to these risks.

Commodity Supply Risk

We enter into short-term, medium-term and long-term natural gas supply contracts, along with associated short-, medium- and long-term transportation capacity contracts. Historically, we have taken physical delivery of at least the minimum quantities specified in our natural gas supply contracts. These contracts are primarily index-based and subject to annual re-pricing, a process that is intended to reflect anticipated market price trends during the next year. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we absorb 33 percent of the higher cost of gas sold, or retain 33 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Market risks related to potential adverse changes in commodity prices, foreign exchange rates or counterparty credit quality in relation to these financial and physical contracts are discussed below.

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion and other factors that affect short-term supply and demand. Commodity-price swap and call option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed prices. These financial hedge contracts are generally included in our annual PGA filing, subject to a prudency review. At December 31, 2006 and 2005, notional amounts under these commodity swap and call option contracts totaled $349.7 million and $470.5 million, respectively. If all of the commodity-price swap and call option contracts had been settled on December 31, 2006, a regulatory loss of $37.8 million would have been realized and deferred (see Note 11). We monitor the liquidity of our financial derivative contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial derivative contracts settle within the next two years. The $37.8 million unrealized loss is an estimate of future cash flows that are expected to be paid as follows: $30.8 million in 2007 and $7.0 million in 2008. The amount realized will change based on market prices at the time contract settlements are fixed.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange

rates with respect to the purchases of natural gas from Canadian suppliers. At December 31, 2006 and 2005, notional amounts under foreign currency forward contracts totaled $5.0 million and $19.9 million, respectively. As of December 31, 2006, no foreign currency forward contracts extended beyond December 31, 2007. If all of the foreign currency forward contracts had been settled on December 31, 2006, a loss of $0.1 million would have been realized (see Note 11).

Credit Risk

Credit exposure to suppliers. Certain suppliers that sell us gas have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers, with no single supplier accounting for more than 20 percent of our total purchases for a given monthly period. We evaluate and continuously monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We believe these costs would be subject to the PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price, and we have significant storage flexibility, we believe that it is unlikely that a supplier default would have a material adverse effect on our financial condition or results of operations.

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity swap and call option contracts was a negative $41.0 million at December 31, 2006. Our Financial Derivatives Policy requires counterparties to have a minimum credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. There were no credit rating downgrades for any of our counterparties during 2006.

The following table summarizes our credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of S&P or Moody's rating, or a middle rating if the entity is split-rated more than one rating level:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
Thousands	Dec. 31, 2	Dec. 31, 2005
AAA/Aaa	$ -	$ -
AA/Aa	(40,955)	172,315
A/A	-	-
BBB/Baa	-	3,346
Total	$ (40,955)	$ 175,661

Credit exposure to customers. Increases in the price of natural gas are expected to increase our credit exposure to customers. However, in the short term, market prices have moderated and resulted in some of our large industrial customers changing from sales services to transportation service. Under sales service, the customer purchases both its gas commodity supply and transportation service from us. Under transportation service, the customer purchases its commodity supplies from an independent third party, with us only providing the transportation service for delivery of that gas to the customer's premise. As a result of this migration from sales service to transportation service, our credit exposure to large industrial customers is expected to moderate. We monitor and manage the credit exposure of

our industrial customers through credit policies and procedures, which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in the services provided to industrial customers as well as changes in market conditions and customers' credit quality. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees and prepayments to reduce our credit exposure.

We also monitor and manage the credit exposure of our residential and commercial customers. This credit risk is largely mitigated by the nature of our regulated business and reasonably short collection terms, as well as by the consistent application of our credit policies and procedures.

Weather Risk

We are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. In 2003, the OPUC approved a weather normalization mechanism for residential and commercial customers. This mechanism affects customer bills between December 1 through May 15 of each winter heating season, increasing or decreasing the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period. The mechanism is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2006, about 9 percent of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10 percent of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is less than 20 percent of all residential and commercial customers.

Interest Rate Risk

We are exposed to interest rate risk associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, locks, options and other hedge products, to manage and mitigate interest rate exposure. At December 31, 2006 and 2005, we had no variable-rate long-term debt and no financial derivative instruments to hedge interest rates. Holders of certain long-term debt have put options that, if exercised, would accelerate maturities by $20 million in each of 2007, 2008 and 2009 (see Note 5 and Note 10).

Forward-Looking Statements

This report and other presentations made by us from time to time may contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and other statements that are other than statements of historical facts. Our expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis. However, each forward-looking statement involves uncertainties and is qualified in its entirety by reference to the following important factors, among others, that could cause our actual results to differ materially from those projected, including:

- prevailing state and federal governmental policies and regulatory actions, including those of the OPUC and the WUTC, with respect to allowed rates of return, industry and rate

structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in tax laws and policies and changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;

- implementation by the OPUC of final rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;
- weather conditions, pandemic events and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;

- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- risks relating to the creditworthiness of customers, suppliers and financial derivative counterparties;
- risks relating to our dependence on a single pipeline transportation provider for natural gas supply;
- risks relating to property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- unanticipated changes that may affect our liquidity or access to capital markets;
- risks relating to the execution of our business process redesign;
- our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;

- unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;
- economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;
- unanticipated changes in operating expenses and capital expenditures;
- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on the fair value of pension assets and on pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New ctors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor or the extent to which any .ictor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (GAAP). Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of NW Natural's internal control over financial reporting as of December 31, 2006. In making this assessment, management used the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*.

Based on our assessment and those criteria, management has concluded that NW Natural maintained effective internal control over financial reporting as of December 31, 2006.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Mark S. Dodson
Mark S. Dodson
esident and Chief Executive Officer

/s/ David H. Anderson
David H. Anderson
Senior Vice President and Chief Financial Officer

February 28, 2007

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

o the Board of Directors and Shareholders of

Northwest Natural Gas Company:

We have completed integrated audits of Northwest Natural Gas Company's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying table of contents presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for share based compensation in 2006 and the manner in which it accounts for defined benefit pension and other postretirement plans effective December 31, 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Controls Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal ntrol over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States).

Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and the board of directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Portland, Oregon

February 28, 2007

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2006	2005	2004
Operating revenues:			
Gross operating revenues	$ 1,013,172	$ 910,486	$ 707,604
Less: Cost of sales	648,156	563,860	399,244
Revenue taxes	24,840	21,633	16,865
Net operating revenues	340,176	324,993	291,495
Operating expenses:			
Operations and maintenance	114,560	113,216	102,155
General taxes	24,419	23,185	21,943
Depreciation and amortization	64,435	61,645	57,371
Total operating expenses	203,414	198,046	181,469
Income from operations	136,762	126,947	110,026
Other income and expense - net	2,134	1,205	2,828
Interest charges - net of amounts capitalized	39,247	37,283	35,751
Income before income taxes	99,649	90,869	77,103
Income tax expense	36,234	32,720	26,531
Net income	$ 63,415	$ 58,149	$ 50,572
Average common shares outstanding:			
Basic	27,540	27,564	27,016
Diluted	27,657	27,621	27,283
Earnings per share of common stock:			
Basic	$ 2.30	$ 2.11	$ 1.87
Diluted	$ 2.29	$ 2.11	$ 1.86

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2006	2005
Assets:		
Plant and property:		
Utility plant	$ 1,963,498	$ 1,875,444
Less accumulated depreciation	574,093	536,867
Utility plant - net	1,389,405	1,338,577
Non-utility property	42,652	40,836
Less accumulated depreciation and amortization	6,916	5,990
Non-utility property - net	35,736	34,846
Total plant and property	1,425,141	1,373,423
Current assets:		
Cash and cash equivalents	5,767	7,143
Accounts receivable	82,070	84,418
Accrued unbilled revenue	87,548	81,512
Allowance for uncollectible accounts	(3,033)	(3,067)
Regulatory assets	31,509	3,879
Fair value of non-trading derivatives	5,109	163,759
Inventories:		
Gas	68,576	77,256
Materials and supplies	9,552	8,905
Income taxes receivable	-	13,234
Prepayments and other current assets	21,695	54,309
Total current assets	308,793	491,348
Investments, deferred charges and other assets:		
Regulatory assets	164,771	94,972
Fair value of non-trading derivatives	1,448	14,894
Other investments	47,985	58,451
Other	8,718	9,216
Total investments, deferred charges and other assets	222,922	177,533
Total assets	$ 1,956,856	$ 2,042,304

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2006	2005
Capitalization and liabilities:		
Capitalization:		
Common stock	$ 371,127	$ 87,334
Premium on common stock	-	296,471
Earnings invested in the business	230,774	205,687
Unearned stock compensation	-	(650)
Accumulated other comprehensive income (loss)	(2,356)	(1,911)
Total common stock equity	599,545	586,931
Long-term debt	517,000	521,500
Total capitalization	1,116,545	1,108,431
Current liabilities:		
Notes payable	100,100	126,700
Long-term debt due within one year	29,500	8,000
Accounts payable	113,579	135,287
Taxes accrued	21,230	12,725
Interest accrued	2,924	2,918
Regulatory liabilities	11,919	163,660
Fair value of non-trading derivatives	38,772	99
Other current and accrued liabilities	21,455	29,916
Total current liabilities	339,479	479,305
Deferred credits and other liabilities:		
Deferred income taxes and investment tax credits	210,084	227,400
Regulatory liabilities	202,982	180,827
Pension and other postretirement benefit liabilities	52,690	17,323
Fair value of non-trading derivatives	11,031	6,777
Other	24,045	22,241
Total deferred credits and other liabilities	500,832	454,568
Commitments and contingencies (see Note 12)	-	-
Total capitalization and liabilities	$ 1,956,856	$ 2,042,304

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND

COMPREHENSIVE INCOME

Thousands	Common Stock and Premium	Earnings Invested in the Business	Unearned Stock Compensation	Accumulated Other Comprehensive Income	Total Shareholders' Equity	Comprehensive Income
Balance at Dec. 31, 2003	$ 338,008	$ 170,053	$ (729)	$ (1,016)	$ 506,316	
Net Income	-	50,572	-	-	50,572	$ 50,572
Minimum pension liability adjustment - net of tax	-	-	-	(802)	(802)	(802)
Purchases of restricted stock	(55)	(51)	(431)	-	(537)	
Restricted stock amortizations	-	-	298	-	298	
Dividends paid on common stock	-	(35,105)	-	-	(35,105)	
Tax benefits from employee stock option plan	872	-	-	-	872	
Issuance of common stock	47,148	-	-	-	47,148	
Convertible debentures	1,292	-	-	-	1,292	
Common stock expense	-	(1,537)	-	-	(1,537)	
Balance at Dec. 31, 2004	387,265	183,932	(862)	(1,818)	568,517	$ 49,770
Net Income	-	58,149	-	-	58,149	$ 58,149
Minimum pension liability adjustment - net of tax	-	-	-	(93)	(93)	(93)
Restricted stock amortizations	-	-	212	-	212	
Dividends paid on common stock	-	(36,376)	-	-	(36,376)	
Tax benefits from employee stock option plan	220	-	-	-	220	
Issuance of common stock	7,266	-	-	-	7,266	
Common stock repurchased	(14,945)	-	-	-	(14,945)	
Convertible debentures	3,999	-	-	-	3,999	
Common stock expense	-	(18)	-	-	(18)	
Balance at Dec. 31, 2005	383,805	205,687	(650)	(1,911)	586,931	$ 58,056
Net Income	-	63,415	-	-	63,415	$ 63,415
Minimum pension liability adjustment - net of tax	-	-	-	(81)	(81)	(81)
Recognition of non-qualified employee benefit plan liability, net of tax				(364)	(364)	
Restricted stock amortizations	298	-	-	-	298	
Dividends paid on common stock	-	(38,298)	-	-	(38,298)	
Tax benefits from employee stock option plan	317	-	-	-	317	
Stock-based compensation	555	-	-	-	555	
Restricted stock reclassification	(650)	-	650	-	-	
Issuance of common stock	2,773	-	-	-	2,773	
Common stock repurchased	(15,971)	-	-	-	(15,971)	
Common stock expense	-	(30)	-	-	(30)	
Balance at Dec. 31, 2006	$ 371,127	$ 230,774	$ -	$ (2,356)	$ 599,545	$ 63,334

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2006	2005	2004
Operating activities:			
Net income	$ 63,415	$ 58,149	$ 50,572
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	64,435	61,645	57,371
Deferred income taxes and investment tax credits	(16,440)	9,551	36,713
Undistributed earnings from equity investments	(191)	(57)	(181)
Deferred gas costs - net	20,752	2,577	(15,178)
Gain on sale of non-utility investments	(495)	-	-
Income from life insurance investments	(2,609)	(1,873)	(2,855)
Contributions to qualified defined benefit pension plans	-	(31,000)	(8,261)
Non-cash expenses related to qualified defined benefit pension plans	5,500	4,532	4,322
Deferred environmental expenditures	(6,675)	(9,132)	(2,215)
Deferred regulatory costs and other	14,533	3,243	3,289
Changes in working capital:			
Accounts receivable and accrued unbilled revenue - net	(3,722)	(40,262)	(16,885)
Inventories of gas, materials and supplies	8,033	(19,684)	(15,618)
Income taxes receivable	13,234	2,736	(6,984)
Prepayments and other current assets	2,952	(3,439)	245
Accounts payable	(21,708)	32,809	16,449
Accrued interest and taxes	8,511	2,504	1,536
Other current and accrued liabilities	(959)	6,767	2,579
Cash provided by operating activities	148,566	79,066	104,899
Investing activities:			
Investment in utility plant	(95,307)	(89,259)	(138,347)
Investment in non-utility property	(1,773)	(6,842)	(10,568)
Proceeds from sale of non-utility investments	2,517	3,001	-
Proceeds from life insurance	4,009	296	17,575
Other	(13)	796	(1,291)
Cash used in investing activities	(90,567)	(92,008)	(132,631)
Financing activities:			
Common stock issued, net of expenses	3,913	7,486	46,616
Common stock repurchased	(15,971)	(14,945)	(537)
Long-term debt issued	25,000	50,000	-
Long-term debt retired	(8,000)	(15,528)	-
Change in short-term debt	(26,600)	24,200	17,300
Cash dividend payments on common stock	(38,298)	(36,376)	(35,105)
Other	581	-	-
Cash (used in) provided by financing activities	(59,375)	14,837	28,274
(Decrease) increase in cash and cash equivalents	(1,376)	1,895	542
Cash and cash equivalents - beginning of period	7,143	5,248	4,706
Cash and cash equivalents - end of period	$ 5,767	$ 7,143	$ 5,248
Supplemental disclosure of cash flow information:			
Interest paid	$ 39,294	$ 36,974	$ 36,061
Income taxes paid	$ 31,270	$ 28,479	$ 2,500
Supplemental disclosure of non-cash financing activities:			
Conversions to common stock:			
7-1/4 % Series of Convertible Debentures	$ -	$ 3,999	$ 1,292

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Thousands (December 31)	2006		2005	
Common stock equity:				
Common stock	$ 371,127		$ 87,334	
Premium on common stock	-		296,471	
Earnings invested in the business	230,774		205,687	
Unearned compensation	-		(650)	
Accumulated other comprehensive income (loss)	(2,356)		(1,911)	
Total common stock equity	599,545	54%	586,931	53%
Long-term debt:				
Medium-Term Notes				
First Mortgage Bonds:				
6.050% Series B due 2006	-		8,000	
6.310% Series B due 2007	20,000		20,000	
6.800% Series B due 2007	9,500		9,500	
6.500% Series B due 2008	5,000		5,000	
4.110% Series B due 2010	10,000		10,000	
7.450% Series B due 2010	25,000		25,000	
6.665% Series B due 2011	10,000		10,000	
7.130% Series B due 2012	40,000		40,000	
8.260% Series B due 2014	10,000		10,000	
4.700% Series B due 2015	40,000		40,000	
5.150% Series B due 2016	25,000		-	
7.000% Series B due 2017	40,000		40,000	
6.600% Series B due 2018	22,000		22,000	
8.310% Series B due 2019	10,000		10,000	
7.630% Series B due 2019	20,000		20,000	
9.050% Series A due 2021	10,000		10,000	
5.620% Series B due 2023	40,000		40,000	
7.720% Series B due 2025	20,000		20,000	
6.520% Series B due 2025	10,000		10,000	
7.050% Series B due 2026	20,000		20,000	
7.000% Series B due 2027	20,000		20,000	
6.650% Series B due 2027	20,000		20,000	
6.650% Series B due 2028	10,000		10,000	
7.740% Series B due 2030	20,000		20,000	
7.850% Series B due 2030	10,000		10,000	
5.820% Series B due 2032	30,000		30,000	
5.660% Series B due 2033	40,000		40,000	
5.250% Series B due 2035	10,000		10,000	
	546,500		529,500	
Less long-term debt due within one year	29,500		8,000	
Total long-term debt	517,000	46%	521,500	47%
Total capitalization	$ 1,116,545	100%	$ 1,108,431	100%

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), our regulated gas distribution business and our regulated gas storage business and a non-regulated wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation).

In this report, the term "utility" is used to describe the regulated gas distribution business and the term "non-utility" is used to describe the gas storage business and other non-regulated activities (see Note 2). Intercompany accounts and transactions have been eliminated.

Investments in corporate joint ventures and partnerships in which our ownership interest is 50 percent or less and over which we do not exercise control are accounted for by the equity method or the cost method (see Note 9).

Certain prior year balances on our consolidated balance sheet have been reclassified to conform with the current presentation. These reclassifications had no impact on our consolidated results of operations, financial condition or cash flows.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates and changes would be reported in future periods. Management believes that the estimates and assumptions used are reasonable.

Industry Regulation

Our principal business is the distribution of natural gas, which is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Accounting records and practices of the regulated business conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation." The utility business segment is authorized by the OPUC and the WUTC to earn a reasonable return on invested capital.

In applying SFAS No. 71, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC in general rate or expense deferral proceedings, to provide for recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge.

At December 31, 2006 and 2005, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		Non-Current	
Thousands	2006	2005	2006	2005
Regulatory assets:				
Gas costs receivable	$ -	$ 2,890	$ -	$ 4,084
Unrealized loss on non-trading derivatives[3]	30,798	-	9,584	-
Income tax asset	-	-	67,141	65,843
Pension and other postretirement benefit obligations[1]	-	-	54,425	-
Environmental costs - paid[2]	-	-	19,113	12,439
Environmental costs - accrued but not yet paid[2]	-	-	8,760	6,440
Other	711	989	5,748	6,166
Total regulatory assets	$ 31,509	$ 3,879	$ 164,771	$ 94,972
Regulatory liabilities:				
Gas costs payable	$ 737	$ -	$ 13,041	$ -
Unrealized gain on non-trading derivatives[3]	-	163,660	-	8,117
Accrued asset removal costs	-	-	187,422	169,927
Other	11,182	-	2,519	2,783
Total regulatory liabilities	$ 11,919	$ 163,660	$ 202,982	$ 180,827

[1] Certain pension and other postretirement benefit obligations required by SFAS No. 158 are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit cost (see Note 7.)

[2] Environmental costs are related to sites that are approved for regulatory deferral. We earn the authorized rate of return as a carrying charge on amounts paid, but the amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.

[3] Unrealized gain or loss on non-trading derivatives do not earn a rate of return or a carrying charge. These amounts, when realized at settlement, are recoverable through utility rates as part of the PGA mechanism.

We believe that continued application of SFAS No. 71 for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2006 and 2005 are recoverable or refundable through future utility rates. We review all regulatory assets at least annually for recoverability. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of SFAS No. 71, then we would be required to write off the net unrecoverable balances against earnings.

New Accounting Standards

Adopted Standards

Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans. In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)." SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of pension and other postretirement

benefit plans. For pension plans, the liability will be based on the projected benefit obligation. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income (AOCI) under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. In addition, the measurement date, which is the date when the fair value of plan assets and benefit obligations are measured, is required to be a company's fiscal year end. The measurement date change did not have an impact on our measurement of benefit obligations or the fair value of plan assets because we previously used our fiscal year end as our measurement date.

Effective December 31, 2006, we adopted SFAS No. 158 and recorded balance sheet adjustments to recognize the funded status of our pension and other postretirement plans. These adjustments did not have a material impact on our results of operations, cash flows or our ability to meet our financial debt covenants. We received regulatory approval from the OPUC for deferred asset recognition of AOCI related to the funded status of certain plans under SFAS No. 71 as these amounts are probable of collection in future rates. As such, we have recognized the unfunded status of our qualified pension plans and our postretirement benefit plan as a deferred regulatory asset, and we will recognize changes in actuarial gains and losses, prior service costs and transition assets or obligations each year as an adjustment to the regulatory deferred asset or liability account as these amounts are recognized as components of net periodic benefit costs each year. See Note 7 for a discussion of pension and other postretirement plans.

Share Based Payment. Effective January 1, 2006, we adopted SFAS No. 123R, "Share Based Payment," using the Modified Prospective Application method without restatement of prior periods. Prior to implementation of SFAS No. 123R, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under this method, we began to amortize compensation cost for the remaining portion of outstanding awards for which the requisite service was not yet rendered at January 1, 2006. Compensation cost for these awards was based on the fair value of the awards at the grant date, which was determined under the intrinsic value method. We determine the fair value of and account for awards that are granted, modified or settled on or after January 1, 2006 in accordance with SFAS No. 123R. The adoption of SFAS No. 123R did not have a material impact on our financial condition, results of operations or cash flows. See Note 4 for a discussion of stock-based compensation.

Accounting for Changes and Error Corrections. Effective January 1, 2006, we adopted SFAS No. 154, "Accounting for Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3," which provides guidance on the accounting for and reporting of accounting changes and error corrections. The statement requires retrospective application to prior periods' financial statements of changes in accounting principles, unless it is impracticable to determine the period-specific effects or the cumulative effect of the change. The guidance provided in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements remains unchanged and requires the restatement of previously issued financial statements. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of SFAS No. 154 did not have an impact upon our financial condition, results of operations or cash flows.

Inventory Costs. Effective January 1, 2006, we adopted SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which amends the guidance on inventory pricing to require that abnormal amounts of idle facility expense, freight, handling costs and wasted material be charged to current period expense rather than capitalized as inventory costs. The adoption of SFAS No. 151 did not have a material impact on our financial condition, results of operations or cash flows.

Purchases and Sales of Inventory with the Same Counterparty. Effective April 1, 2006, we adopted FASB Emerging Issues Task Force (EITF) Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF 04-13 requires that two or more legally separate exchange transactions with the same counterparty be combined and considered a single arrangement for purposes of applying APB Opinion No. 29, "Accounting for Nonmonetary Transactions," when the transactions are entered into in contemplation of one another. EITF 04-13 was effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006. Adoption of this standard did not have a material impact on our financial condition, results of operations or cash flows.

Variable Interest Entities. In April 2006, the FASB issued a staff position (FSP) interpreting variable interest entities (VIE) under FASB Interpretation No. (FIN) 46(R)-6, "Determining the Variability to be Considered in Applying FIN 46(R)." This FSP emphasizes that preparers should use a "by design" approach in determining whether an interest is variable. A "by design" approach includes evaluating whether an interest is variable based on a thorough understanding of the design of the potential VIE, including the nature of the risks that the potential VIE was designed to create and pass along to interest holders in the entity. Consolidation of a VIE by the primary beneficiary is required if it is determined that the VIE does not effectively disperse risks among the parties involved. FSP No. FIN 46(R)-6 must be applied prospectively to all entities with which the company first becomes involved and to all entities previously required to be analyzed under FIN 46(R) when a reconsideration event has occurred effective on or after July 1, 2006. Implementation of FSP No. FIN 46(R)-6 did not have a material impact on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

Accounting for Certain Hybrid Instruments. In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Instruments," which amends SFAS Nos. 133 "Accounting for Derivative Instruments and Hedging Activities," and 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. The statement is effective for all financial instruments acquired or issued after January 1, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 155, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

Accounting for Uncertainty in Income Taxes. In July 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109," which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return.

FIN 48 is effective as of the beginning of the first annual period after December 15, 2006, or January 1, 2007. It replaces the "probable" and "reasonable estimate" standards of SFAS No. 5 with a two-step approach for determining the amount of tax benefits (thus treating "loss contingencies" and "gain contingencies" consistently) to be recorded in a company's financial statements. Management is required to evaluate all tax positions taken for each jurisdiction and determine the likelihood of the positions being sustained. If management is highly confident that a tax position will be sustained and there is a greater than 50 percent likelihood that the full amount of the tax position will be ultimately realized, a company would recognize the full benefit associated with the tax position.

New disclosures under FIN 48 will primarily consist of:

- A policy on classification of interest and penalties (either as components of operating income or components of the income tax provision);
- A tabular reconciliation of the total amounts of unrecognized tax benefits at the beginning and end of the period;
- The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; and,
- A description of tax years that remain subject to examination by major tax jurisdictions.

Adoption of FIN 48 will require us to identify and evaluate all material tax positions taken in previously filed and currently open tax returns as well as tax positions expected to be taken in future returns. Each tax position will need to be examined to determine whether the more likely than not recognition standard has been met, and if so, to compute the amount of the tax benefit to be recognized under FIN 48. Based upon a preliminary assessment of the application of FIN 48, the adoption of FIN 48 is not expected to have a material effect on our financial condition, results of operations or cash flows. See Note 8.

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides a common definition for the measurement of fair value for use in applying GAAP and in preparing financial statement disclosures. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 157, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

Plant and Property and Accrued Asset Removal Costs

Plant and property is stated at cost, including capitalized labor, materials and overhead (see Note 9). The cost of constructing utility plant and gas storage assets includes an allowance for funds used during construction, which represents the net financing cost during the period of funds used for construction purposes (see "Allowance for Funds Used During Construction," below).

Our provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with independent engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for utility plant in service was approximately 3.4 percent for the each of the years ended December 31, 2006, 2005 and 2004, reflecting the approximate economic life of the property.

In accordance with long-standing industry practice, we accrue for future asset removal costs on many long-lived assets through a charge to depreciation expense allowed in rates and accumulate such amounts in regulatory liabilities. At the time removal costs are incurred, accumulated depreciation is charged with the costs of removal and the book cost of the asset. Our estimate of accumulated removal costs is based on rates using our most recent depreciation study. No gain or loss is recognized upon normal retirement. In the rate setting process, the accrued asset removal costs are treated as a reduction to the net rate base.

Allowance for Funds Used During Construction

Certain additions to utility plant include an allowance for funds used during construction, which represents the net cost of borrowed or other funds used during construction and is calculated using actual current interest rates. If borrowings are less than the total costs of construction work in progress, then a composite rate of interest on all debt, shown as a reduction to interest charges, and a return on equity funds, shown as other income, is used to compute the allowance. While cash is not realized currently from allowance for funds used during construction, it is realized in future years through increased revenues from rate recovery resulting from higher rate base and higher depreciation expense. Our composite allowance for funds used during construction rates were 4.7 percent in 2006, 3.1 percent in 2005 and 3.0 percent in 2004.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand and highly liquid temporary investments with original maturity dates of three months or less. At December 31, 2006 and 2005, book overdrafts of $3.7 million and $4.1 million, respectively, were included within accounts payable.

Revenue Recognition and Accrued Unbilled Revenues

Utility revenues, derived primarily from the sale and transportation of gas, are recognized when the gas is delivered to and received by the customer. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of gas deliveries from meter reading dates to month end (accrued unbilled revenues). Accrued unbilled revenues are dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use and weather. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2006 and 2005 were $87.5 million and $81.5 million, respectively.

Non-utility revenues, derived primarily from gas storage services, are recognized upon delivery of the service to customers. Revenues from optimization of excess storage and transportation capacity include amounts that are recognized ratably over the life of the contract for guaranteed amounts, or as earned for amounts above the guaranteed amount based on the terms of our contract with the independent energy marketing company which optimizes the value of our assets primarily through the use of commodity transactions and capacity release transactions (see Note 2).

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for gas sales and transportation services to core (residential, commercial and industrial firm) customers, plus amounts due for gas storage and other miscellaneous receivables. With respect to these trade receivables and accrued unbilled revenues, we establish an allowance for uncollectible accounts (allowance) based on the aging of receivables, collection experience of past due accounts on payment plans, and historical trends of write-offs as a percent of revenues. With respect to large individual customer receivables, a specific allowance is established and added to the general allowance when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after 120 days past due or when deemed to be uncollectible. Differences between our estimated allowance and actual write-offs will occur based on changes in general economic conditions, customer credit issues and the level of natural gas prices. Each quarter the allowance for the uncollectible accounts is adjusted, if necessary, based on the most current information available.

Inventories

Inventories, which consist primarily of natural gas in storage for the utility, are generally stated at the lower of average cost or net realizable value. The regulatory treatment of gas inventories provides for full cost recovery in customer rates, subject to a prudency review, including any differences between the actual purchase cost of gas injected into inventory and the embedded cost of inventory in current rates. All gas that is injected into storage is priced into inventory at the actual purchase cost based on a regulatory dispatch model for our gas purchases. All gas that is withdrawn from inventory is charged to cost of gas during the current period at the weighted average cost of inventory embedded in customer rates, which is established in our annual purchased gas adjustment (PGA) filing. Material and supplies inventories are stated at the lower of average cost or net realizable value.

Derivatives

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (collectively referred to as SFAS No. 133), we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. SFAS No. 133 requires that changes in the fair value of a derivative be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS No. 133 provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivatives contracts are approved by regulatory authorities for recovery through customer rates. Accordingly, the changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS No. 71. Derivatives contracts entered into for core utility customer requirements after the PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 percent is recorded to the income statement (see Note 11).