CHESAPEAKE ENERGY CORP
Form 10-Q
November 07, 2006
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended September 30, 2006

¨ Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to

Commission File No. 1-13726

Chesapeake Energy Corporation

(Exact name of registrant as specified in its charter)

Oklahoma	**73-1395733**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
6100 North Western Avenue	
Oklahoma City, Oklahoma	**73118**
(Address of principal executive offices)	**(Zip Code)**

(405) 848-8000

Registrant s telephone number, including area code

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

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.

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

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

As of November 3, 2006, there were 436,865,417 shares of our $0.01 par value common stock outstanding.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

	September 30, 2006	December 31, 2005
	($ in thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 716	$ 60,027
Accounts receivable	735,005	791,194
Deferred income taxes		234,592
Short-term derivative instruments	1,097,578	10,503
Inventory and other	78,996	87,081
Total Current Assets	1,912,295	1,183,397
PROPERTY AND EQUIPMENT:		
Oil and natural gas properties, at cost based on full-cost accounting:		
Evaluated oil and natural gas properties	20,191,783	15,880,919
Unevaluated properties	3,440,181	1,739,095
Less: accumulated depreciation, depletion and amortization of oil and natural gas properties	(4,913,749)	(3,945,703)
Total oil and natural gas properties, at cost based on full-cost accounting	18,718,215	13,674,311
Other property and equipment:		
Natural gas gathering systems	457,321	333,365
Drilling rigs	301,611	116,133
Buildings and land	381,751	233,467
Natural gas compressors	108,847	73,043
Other	205,781	110,208
Less: accumulated depreciation and amortization of other property and equipment	(172,563)	(128,640)
Total Property and Equipment	20,000,963	14,411,887
OTHER ASSETS:		
Investments	686,343	297,443
Long-term derivative instruments	604,796	78,860
Other assets	190,524	146,875
Total Other Assets	1,481,663	523,178
TOTAL ASSETS	$ 23,394,921	$ 16,118,462

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

	September 30, 2006	December 31, 2005
	($ in thousands)	
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 754,996	$ 516,792
Short-term derivative instruments	81,438	577,681
Other accrued liabilities	398,611	364,501
Deferred income taxes	369,410	
Revenues and royalties due others	305,422	394,693
Accrued interest	94,395	110,421
Total Current Liabilities	2,004,272	1,964,088
LONG-TERM LIABILITIES:		
Long-term debt, net	7,861,108	5,489,742
Deferred income tax liability	2,903,688	1,804,978
Asset retirement obligation	179,149	156,593
Long-term derivative instruments	181,941	479,996
Revenues and royalties due others	22,962	22,585
Other liabilities	48,981	26,157
Total Long-Term Liabilities	11,197,829	7,980,051
CONTINGENCIES AND COMMITMENTS (Note 3)		
STOCKHOLDERS EQUITY:		
Preferred Stock, $.01 par value, 20,000,000 shares authorized:		
6.00% cumulative convertible preferred stock, 0 and 99,310 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $0 and $4,965,500		4,966
5.00% cumulative convertible preferred stock (series 2003), 38,625 and 1,025,946 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $3,862,500 and $102,594,600	3,863	102,595
4.125% cumulative convertible preferred stock, 3,065 and 89,060 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $3,065,000 and $89,060,000	3,065	89,060
5.00% cumulative convertible preferred stock (series 2005), 4,600,000 shares issued and outstanding as of September 30, 2006 and December 31, 2005, entitled in liquidation to $460,000,000	460,000	460,000
4.50% cumulative convertible preferred stock, 3,450,000 shares issued and outstanding as of September 30, 2006 and December 31, 2005, entitled in liquidation to $345,000,000	345,000	345,000
5.00% cumulative convertible preferred stock (series 2005B), 5,750,000 shares issued and outstanding as of September 30, 2006 and December 31, 2005, entitled in liquidation to $575,000,000	575,000	575,000
6.25% mandatory convertible preferred stock, 2,300,000 and 0 shares issued and outstanding as of September 30, 2006 and December 31, 2005, respectively, entitled in liquidation to $575,000,000 and $0	575,000	
Common Stock, $.01 par value, 750,000,000 and 500,000,000 shares authorized, 437,859,397 and 375,510,521 shares issued at September 30, 2006 and December 31, 2005, respectively	4,379	3,755
Paid-in capital	4,899,634	3,803,312
Retained earnings	2,495,215	1,100,841

Accumulated other comprehensive income (loss), net of tax of ($518,564,000) and $112,071,000, respectively	862,241	(194,972)
Unearned compensation		(89,242)
Less: treasury stock, at cost; 1,306,528 and 5,320,816 common shares as of September 30, 2006 and December 31, 2005, respectively	(30,577)	(25,992)
Total Stockholders Equity	10,192,820	6,174,323
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 23,394,921	$ 16,118,462

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	($ in thousands, except per share data)			
REVENUES:				
Oil and natural gas sales	$ 1,493,226	$ 720,928	$ 4,190,430	$ 2,032,271
Oil and natural gas marketing sales	398,114	361,915	1,170,091	882,040
Service operations revenue	38,071		97,473	
Total Revenues	1,929,411	1,082,843	5,457,994	2,914,311
OPERATING COSTS:				
Production expenses	124,045	80,765	364,134	222,660
Production taxes	40,562	53,102	129,858	136,313
General and administrative expenses	37,382	15,785	99,728	39,640
Oil and natural gas marketing expenses	384,473	353,510	1,131,521	860,789
Service operations expense	18,821		48,925	
Oil and natural gas depreciation, depletion and amortization	343,723	231,145	976,839	621,484
Depreciation and amortization of other assets	27,016	12,902	74,051	34,791
Employee retirement expense			54,753	
Total Operating Costs	976,022	747,209	2,879,809	1,915,677
INCOME FROM OPERATIONS	953,389	335,634	2,578,185	998,634
OTHER INCOME (EXPENSE):				
Interest and other income	5,132	2,428	19,742	7,790
Interest expense	(74,112)	(58,593)	(220,226)	(155,623)
Gain on sale of investment			117,396	
Loss on repurchases or exchanges of Chesapeake senior notes		(747)		(70,047)
Total Other Income (Expense)	(68,980)	(56,912)	(83,088)	(217,880)
INCOME BEFORE INCOME TAXES	884,409	278,722	2,495,097	780,754
INCOME TAX EXPENSE:				
Current				
Deferred	336,074	101,734	963,136	284,977
Total Income Tax Expense	336,074	101,734	963,136	284,977
NET INCOME	548,335	176,988	1,531,961	495,777
PREFERRED STOCK DIVIDENDS	(25,753)	(10,204)	(62,793)	(25,526)
LOSS ON CONVERSION/EXCHANGE OF PREFERRED STOCK		(17,725)	(10,556)	(22,468)
NET INCOME AVAILABLE TO COMMON SHAREHOLDERS	$ 522,582	$ 149,059	$ 1,458,612	$ 447,783

EARNINGS PER COMMON SHARE:

Basic	$	1.25	$	0.46	$	3.75	$	1.42
Assuming dilution	$	1.13	$	0.43	$	3.40	$	1.32
CASH DIVIDEND DECLARED PER COMMON SHARE	$	0.060	$	0.050	$	0.170	$	0.145
WEIGHTED AVERAGE COMMON AND COMMON EQUIVALENT SHARES OUTSTANDING (in thousands):								
Basic		417,569		322,101		389,136		314,425
Assuming dilution		483,273		367,639		450,680		352,210

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30, 2006	2005
	($ in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
NET INCOME	$ 1,531,961	$ 495,777
ADJUSTMENTS TO RECONCILE NET INCOME TO CASH PROVIDED BY OPERATING ACTIVITIES:		
Depreciation, depletion and amortization	1,041,246	649,907
Unrealized (gains) losses on derivatives	(453,347)	135,175
Deferred income taxes	963,136	284,977
Amortization of loan costs and bond discount	14,952	10,576
Realized (gains) losses on financing derivatives	(96,377)	
Stock-based compensation	78,200	10,172
Gain on sale of investment in Pioneer Drilling Company	(117,396)	
Income from equity investments	(9,187)	(2,171)
Loss on repurchases or exchanges of Chesapeake senior notes		70,047
Premiums paid for repurchasing of senior notes		(61,023)
Other	(3,556)	(503)
Change in assets and liabilities	32,787	(15,589)
Cash provided by operating activities	2,982,419	1,577,345
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions of oil and natural gas companies, proved and unproved properties, net of cash acquired	(3,089,710)	(1,932,934)
Exploration and development of oil and natural gas properties	(2,583,841)	(1,488,145)
Additions to buildings and other fixed assets	(406,752)	(156,978)
Additions to drilling rig equipment	(340,814)	(42,056)
Proceeds from sale of investment in Pioneer Drilling Company	158,890	
Proceeds from sale of drilling rigs and equipment	187,500	
Additions to investments	(537,703)	(37,273)
Acquisition of trucking company, net of cash acquired	(45,166)	
Deposits for acquisitions	(12,070)	
Other	1,661	2,342
Cash used in investing activities	(6,668,005)	(3,655,044)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings	7,058,000	3,561,000
Payments on long-term borrowings	(5,666,000)	(3,620,000)
Proceeds from issuance of senior notes, net of offering costs	969,193	1,765,383
Proceeds from issuance of common stock, net of offering costs	803,720	289,391
Proceeds from issuance of preferred stock, net of offering costs	557,627	782,368
Purchases or exchanges of Chesapeake senior notes		(556,407)
Common stock dividends	(61,829)	(45,771)
Preferred stock dividends	(62,541)	(17,315)
Financing costs of credit facility	(5,079)	(4,672)
Purchases of treasury shares	(86,185)	(4,000)
Derivative settlements	(68,361)	

Net increase in outstanding payments in excess of cash balance	43,250	33,751
Cash received from exercise of stock options and warrants	71,254	19,940
Excess tax benefit from stock-based compensation	85,649	
Other financing costs	(12,423)	(5,763)
Cash provided by financing activities	3,626,275	2,197,905
Net increase (decrease) in cash and cash equivalents	(59,311)	120,206
Cash and cash equivalents, beginning of period	60,027	6,896
Cash and cash equivalents, end of period	$ 716	$ 127,102

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)

(Unaudited)

	Nine Months Ended September 30, 2006	2005
	($ in thousands)	
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION OF CASH PAYMENTS FOR:		
Interest, net of capitalized interest	$ 245,190	$ 162,218
Income taxes, net of refunds received	$	$
SUPPLEMENTAL SCHEDULE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:		

In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, with estimated proved reserves of approximately 618 bcfe and daily production of approximately 83 mmcfe.

For the nine months ended September 30, 2006 and 2005, holders of our 6.0% cumulative convertible preferred stock converted 99,310 and 1,835 shares, respectively, into 482,694 and 8,918 shares, respectively, of common stock.

For the nine months ended September 30, 2006 and 2005, holders of our 4.125% cumulative convertible preferred stock exchanged 2,750 and 178,675 shares, respectively, for 172,594 and 11,441,008 shares, respectively, of common stock in privately negotiated exchanges.

For the nine months ended September 30, 2006 and 2005, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 and 697,724 shares, respectively, for 1,140,223 and 4,354,439 shares, respectively, of common stock in privately negotiated exchanges.

During the nine months ended September 30, 2006, we completed tender offers for our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock, issuing 5.2 million shares of our common stock in exchange for 83,245 shares of the 4.125% preferred stock, which represented 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, and 5.0 million shares of our common stock in exchange for 804,048 shares of the 5.0% (Series 2003) preferred stock, which represented 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding. No cash was received or paid in connection with these transactions.

As of September 30, 2006 and 2005, dividends payable on our common and preferred stock were $51.1 million and $28.7 million, respectively.

For the nine months ended September 30, 2006 and 2005, oil and natural gas properties were adjusted by $177.7 million and $253.2 million, respectively, for net income tax liabilities related to acquisitions.

For the nine months ended September 30, 2006 and 2005, $72.6 million and $22.4 million, respectively, of accrued exploration and development costs were recorded as additions to oil and natural gas properties.

We recorded non-cash asset additions to net oil and natural gas properties of $13.7 million and $8.0 million for the nine months ended September 30, 2006 and 2005, respectively, for asset retirement obligations.

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(Unaudited)

	Nine Months Ended September 30, 2006	2005
	($ in thousands)	
PREFERRED STOCK:		
Balance, beginning of period	$ 1,576,621	$ 490,906
Issuance of 6.25% mandatory convertible preferred stock	575,000	
Issuance of 5.00% cumulative convertible preferred stock (Series 2005)		460,000
Issuance of 4.50% cumulative convertible preferred stock		345,000
Exchange of common stock for 85,995 and 178,675 shares of 4.125% preferred stock	(85,995)	(178,675)
Exchange of common stock for 987,321 and 697,724 shares of 5.00% preferred stock (Series 2003)	(98,732)	(69,772)
Exchange of common stock for 99,310 and 1,835 shares of 6.00% preferred stock	(4,966)	(92)
Balance, end of period	1,961,928	1,047,367
COMMON STOCK:		
Balance, beginning of period	3,755	3,169
Issuance of 28,750,000 and 9,200,000 shares of common stock	288	92
Issuance of 1,375,989 shares of common stock for the purchase of Chaparral Energy, Inc. common stock	14	
Exchange of 12,016,423 and 15,804,365 shares of common stock for preferred stock	120	158
Exercise of stock options and warrants	67	38
Restricted stock grants	135	37
Balance, end of period	4,379	3,494
PAID-IN CAPITAL:		
Balance, beginning of period	3,803,312	2,440,105
Issuance of common stock	834,900	300,932
Issuance of common stock for the purchase of Chaparral Energy, Inc. common stock	39,986	
Exchange of 12,016,423 and 15,804,365 shares of common stock for preferred stock	189,572	248,381
Equity-based compensation	88,989	78,943
Adoption of SFAS 123(R)	(89,242)	
Offering expenses	(48,829)	(34,302)
Exercise of stock options and warrants	71,187	19,902
Release of 6,500,000 shares from treasury stock upon exercise of stock options	(75,102)	
Tax benefit from exercise of stock options and restricted stock	85,649	17,397
Preferred stock conversion/exchange expenses	(788)	(103)
Balance, end of period	4,899,634	3,071,255
RETAINED EARNINGS:		
Balance, beginning of period	1,100,841	262,987
Net income	1,531,961	495,777
Dividends on common stock	(68,789)	(46,612)
Dividends on preferred stock	(68,798)	(25,726)
Balance, end of period	2,495,215	686,426
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):		
Balance, beginning of period	(194,972)	20,425
Hedging activity	1,143,738	(546,305)
Marketable securities activity	(86,525)	44,440

Balance, end of period	862,241	(481,440)
UNEARNED COMPENSATION:		
Balance, beginning of period	(89,242)	(32,618)
Restricted stock granted		(78,148)
Amortization of unearned compensation		16,075
Adoption of SFAS 123(R)	89,242	
Balance, end of period		(94,691)
TREASURY STOCK COMMON:		
Balance, beginning of period	(25,992)	(22,091)
Purchase of 2,707,471 and 257,220 shares of treasury stock	(86,185)	(4,000)
Release of 6,500,000 shares upon exercise of stock options	75,102	
Release of 221,759 shares for company benefit plans	6,498	
Balance, end of period	(30,577)	(26,091)
TOTAL STOCKHOLDERS EQUITY	$ 10,192,820	$ 4,206,320

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30, 2006	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	($ in thousands)			
Net income	$ 548,335	$ 176,988	$ 1,531,961	$ 495,777
Other comprehensive income, net of income tax:				
Change in fair value of derivative instruments, net of income taxes of $451,888,000, ($345,346,000), $1,084,370,000 and ($389,909,000)	750,588	(600,807)	1,799,636	(678,334)
Reclassification of (gain) loss on settled contracts, net of income taxes of ($105,162,000), $40,815,000, ($268,896,000) and $39,798,000	(174,040)	71,007	(444,770)	69,238
Ineffective portion of derivatives qualifying for cash flow hedge accounting, net of income taxes of ($64,099,000), $36,307,000, ($125,599,000) and $36,092,000	(107,730)	63,165	(211,128)	62,791
Unrealized gain (loss) on marketable securities, net of income taxes of ($2,336,000), $12,046,000, ($7,995,000) and $25,544,000	(3,926)	20,957	(13,439)	44,440
Reclassification of gain on sales of investments, net of income taxes of $0, $0, ($45,824,000) and $0			(73,086)	
Comprehensive income	$ 1,013,227	$ (268,690)	$ 2,589,174	$ (6,088)

The accompanying notes are an integral part of these condensed consolidated financial statements.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

Principles of Consolidation

The accompanying unaudited condensed consolidated financial statements of Chesapeake Energy Corporation and its subsidiaries have been prepared in accordance with the instructions to Form 10-Q as prescribed by the Securities and Exchange Commission. Chesapeake s 2005 Annual Report on Form 10-K includes certain definitions and a summary of significant accounting policies and should be read in conjunction with this Form 10-Q. All material adjustments (consisting solely of normal recurring adjustments) which, in the opinion of management, are necessary for a fair statement of the results for the interim periods have been reflected. The results for the three and nine months ended September 30, 2006 are not necessarily indicative of the results to be expected for the full year. This Form 10-Q relates to the three and nine months ended September 30, 2006 (the Current Quarter and the Current Period , respectively) and the three and nine months ended September 30, 2005 (the Prior Quarter and the Prior Period , respectively).

Stock-Based Compensation

On January 1, 2006, we adopted Statement of Financial Accounting Standards No. 123 (revised 2004), *Share-Based Payment* (SFAS 123(R)), to account for stock-based compensation. Among other items, SFAS 123(R) eliminates the use of APB Opinion No. 25 and the intrinsic value method of accounting for equity compensation and requires companies to recognize the cost of employee services received in exchange for awards of equity instruments based on the fair value at grant date of those awards in their financial statements. We elected to use the modified prospective method for adoption, which requires compensation expense to be recorded for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. For all unvested options outstanding as of January 1, 2006, the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in our financial statements over the remaining vesting period. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense based on the fair value on the date of grant or modification will be recognized in our financial statements over the vesting period. We utilize the Black-Scholes option pricing model to measure the fair value of stock options. To the extent compensation cost relates to employees directly involved in oil and natural gas exploration and development activities, such amounts are capitalized to oil and natural gas properties. Amounts not capitalized to oil and natural gas properties are recognized as general and administrative expenses or production expenses.

Prior to the adoption of SFAS 123(R), we followed the intrinsic value method in accordance with APB 25 to account for employee stock-based compensation. Prior period financial statements have not been restated. Upon adoption of SFAS 123(R), we eliminated $89.2 million of unearned compensation cost and reduced additional paid-in capital by the same amount on our condensed consolidated balance sheet.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the three and nine months ended September 30, 2006 and 2005, we recorded the following stock-based compensation ($ in thousands):

	Restricted Stock		Stock Options		Total	
For the Three Months Ended September 30:	**2006**	**2005**	**2006**	**2005**	**2006**	**2005**
Production expenses	$ 2,742	$	$ 143	$	$ 2,885	$
General and administrative expenses	7,949	4,315	530	934	8,479	5,249
Oil and natural gas properties	9,452	3,676	492	1,390	9,944	5,066
Total	$ 20,143	$ 7,991	$ 1,165	$ 2,324	$ 21,308	$ 10,315
For the Nine Months Ended September 30:						
Production expenses	$ 5,191	$	$ 523	$	$ 5,714	$
General and administrative expenses	18,066	8,837	3,190	1,335	21,256	10,172
Employee retirement expense	35,720		15,510		51,230	
Oil and natural gas properties	17,739	7,395	1,755	1,390	19,494	8,785
Total	$ 76,716	$ 16,232	$ 20,978	$ 2,725	$ 97,694	$ 18,957

The impact to income before income taxes of adopting SFAS 123(R) for the Current Quarter and the Current Period was a reduction of $0.6 million and $2.5 million, respectively. SFAS 123(R) also requires cash inflows resulting from tax deductions in excess of compensation expense recognized for stock options and restricted stock (excess tax benefits) to be classified as financing cash inflows in our statements of cash flows. Accordingly, for the nine months ended September 30, 2006, we reported $85.6 million of excess tax benefits from stock-based compensation as cash provided by financing activities on our statement of cash flows.

Pro forma Disclosures

Prior to January 1, 2006, we accounted for our employee and non-employee director stock options using the intrinsic value method prescribed by APB 25. As required by SFAS 123(R), we have disclosed below the effect on net income and earnings per share that would have been recorded using the fair value based method for the three and nine months ended September 30, 2005 ($ in thousands, except per share amounts):

	Three Months Ended September 30, 2005	Nine Months Ended September 30, 2005
Net Income:		
As reported	$ 176,988	$ 495,777
Add: Stock-based compensation expense included in reported net income, net of income tax	3,333	6,459
Deduct: Total stock-based compensation expense determined under fair value based method for all awards, net of income tax	(5,218)	(13,176)
Pro forma net income	$ 175,103	$ 489,060
Basic earnings per common share:		
As reported	$ 0.46	$ 1.42

Pro forma	$	0.46	$	1.40
Diluted earnings per common share:				
As reported	$	0.43	$	1.32
Pro forma	$	0.42	$	1.30

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock

Chesapeake began issuing shares of restricted common stock to employees in January 2004 and to non-employee directors in July 2005. The fair value of the awards issued is determined based on the fair market value of the shares on the date of grant. This value is amortized over the vesting period, which is four or five years from the date of grant for employees and three years for non-employee directors.

A summary of the status of the unvested shares of restricted stock as of September 30, 2006, and changes during the Current Period, is presented below:

	Number of Unvested Restricted Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2006	5,805,210	$ 18.38
Granted	14,183,418	32.12
Vested	(2,794,835)	19.73
Forfeited	(315,948)	25.76
Unvested shares as of September 30, 2006	16,877,845	$ 29.57

The aggregate intrinsic value of restricted stock vested during the Current Period was approximately $85.4 million.

Included in the 14.2 million shares of restricted stock granted during the Current Period are 9.9 million shares of restricted stock granted during the Current Quarter to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in three years with the remaining 50% vesting in five years.

As of September 30, 2006, there was $478.6 million of total unrecognized compensation cost related to unvested restricted stock. The cost is expected to be recognized over a weighted average period of 4.09 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to restricted stock of $1.3 million, $1.5 million, $4.3 million and $1.6 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Stock Options

We granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable over a four-year period.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides information related to stock option activity during the Current Period:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Contract Life in Years	Aggregate Intrinsic Value[(a)] ($ in thousands)
Outstanding at January 1, 2006	20,256,013	$ 6.14		
Exercised	(13,198,705)	5.32		
Forfeited	(72,713)	9.18		
Outstanding at September 30, 2006	6,984,595	$ 7.65	5.54	$ 149,081
Exercisable at September 30, 2006	5,688,614	$ 7.31	5.30	$ 123,403

(a) The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option.

The aggregate intrinsic value of stock options exercised during the Current Period was approximately $345.0 million.

As of September 30, 2006, there was $2.5 million of total unrecognized compensation cost related to unvested stock options. The cost is expected to be recognized over a weighted average period of 0.52 years.

During the Current Quarter, the Prior Quarter, the Current Period and the Prior Period, we recognized excess tax benefits related to stock options of $2.8 million, $7.4 million, $81.3 million and $15.8 million, respectively, which were recorded as adjustments to additional paid-in capital and deferred income taxes with respect to such benefits.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2005.

2. Financial Instruments and Hedging Activities

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

In accordance with FASB Interpretation No. 39, to the extent that a legal right of set-off exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets.

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or natural gas from a specified delivery point. We currently have basis protection swaps covering six different

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

delivery points, four in the Mid-Continent and two in the Appalachian Basin, which correspond to the actual prices we receive for much of our natural gas production. By entering into these basis protection swaps, we have effectively reduced our exposure to market changes in future natural gas price differentials. As of September 30, 2006, the fair value of our basis protection swaps was $178.8 million. As of September 30, 2006, our Mid-Continent basis protection swaps cover approximately 29% of our anticipated remaining Mid-Continent natural gas production in 2006, 25% in 2007, 18% in 2008 and 13% in 2009. As of September 30, 2006, our Appalachian Basin basis protection swaps cover approximately 74% of our anticipated Appalachian Basin natural gas production in 2007, 65% in 2008 and 30% in 2009.

Gains or losses from certain derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $301.4 million, ($122.6) million, $807.1 million and ($126.6) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $238.5 million, ($104.0) million, $452.6 million and ($137.1) million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $171.8 million, ($99.5) million, $336.7 million and ($98.9) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

The estimated fair values of our oil and natural gas derivative instruments as of September 30, 2006 and December 31, 2005 are provided below. The associated carrying values of these instruments are equal to the estimated fair values.

	September 30, 2006	**December 31, 2005**
	($ in thousands)	
Derivative assets (liabilities):		
Fixed-price natural gas swaps	$ 1,234,681	$ (1,047,094)
Natural gas basis protection swaps	178,832	307,308
Fixed-price natural gas cap-swaps	69,136	(161,056)
Fixed-price natural gas counter-swaps	6,646	37,785
Natural gas call options (a)	(21,816)	(21,461)
Fixed-price natural gas collars	(7,016)	(9,374)
Fixed-price natural gas locked swaps	(16,333)	(34,229)
Floating-price natural gas swaps		2,607
Fixed-price oil swaps	13,547	(16,936)
Fixed-price oil cap-swaps	18,317	(3,364)
Estimated fair value	$ 1,475,994	$ (945,814)

(a) After adjusting for $49.6 million and $23.0 million of unrealized premiums, the cumulative unrealized gain related to these call options as of September 30, 2006 and December 31, 2005 was $27.8 million and $1.6 million, respectively.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Based upon the market prices at September 30, 2006, we expect to transfer approximately $530.2 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of September 30, 2006 are expected to mature by December 31, 2009.

We have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for each of these facilities is May 2010. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. Both of the hedging facilities are subject to a 1.0% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of September 30, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $252.1 million under one of the facilities and an asset of $823.2 million under the other facility. As of November 3, 2006, the fair market value of the same transactions was an asset of approximately $152.2 million and $255.5 million, respectively. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate natural gas and oil production volumes that we are permitted to hedge under all of our agreements at any one time.

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed does not change, then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element, and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

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The following details the assumed CNR derivatives remaining as of September 30, 2006:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at September 30, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
4Q 2006	10,626,000	$ 4.86	$	$	Yes	$ (9,313)
1Q 2007	10,350,000	4.82			Yes	(30,297)
2Q 2007	10,465,000	4.82			Yes	(24,548)
3Q 2007	10,580,000	4.82			Yes	(26,672)
4Q 2007	10,580,000	4.82			Yes	(33,722)
1Q 2008	9,555,000	4.68			Yes	(39,074)
2Q 2008	9,555,000	4.68			Yes	(23,387)
3Q 2008	9,660,000	4.68			Yes	(24,581)
4Q 2008	9,660,000	4.66			Yes	(29,997)
1Q 2009	4,500,000	5.18			Yes	(14,498)
2Q 2009	4,550,000	5.18			Yes	(7,627)
3Q 2009	4,600,000	5.18			Yes	(8,162)
4Q 2009	4,600,000	5.18			Yes	(10,574)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(2,538)
2Q 2009	910,000		4.50	6.00	Yes	(1,268)
3Q 2009	920,000		4.50	6.00	Yes	(1,375)
4Q 2009	920,000		4.50	6.00	Yes	(1,835)
Total Natural Gas						$ (289,468)

Subsequent to September 30, 2006, Chesapeake lifted a portion of its fourth quarter 2006 and full-year 2007, 2008 and 2009 hedges and as a result received $407 million in cash from its hedging counterparties. The gain will be recorded in accumulated other comprehensive income and in unrealized oil and natural gas sales based on the designation of the hedges. The gain will be recognized in realized oil and natural gas sales in the month of the hedged production.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.6) million, $0.8 million, $0.9 million and $2.6 million in the Current

Quarter, Prior Quarter, Current Period and

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Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $2.5 million, ($1.2) million, $0.8 million and $1.9 million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

As of September 30, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,919)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(6,301)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,456)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(7,305)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(3,308)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(7,124)
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points	(3,178)
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points	(172)
				$ (36,763)

In the Current Period, we closed three interest rate swaps for gains totaling $3.0 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

To mitigate our short-term exposure to rising interest rates on a portion of our long-term debt that has been converted to floating-rate, we have entered into zero-cost collar transactions. These collars contain a fixed floor rate (put) and fixed ceiling rate (call). If LIBOR exceeds the ceiling rate or falls below the floor rate, Chesapeake pays the fixed rate and receives LIBOR. If LIBOR is between the ceiling and floor rates, no payments are due from either party. As of September 30, 2006, we were a party to the following zero-cost interest rate collars:

Payment Dates	Notional Amount	LIBOR Floor	LIBOR Ceiling
July 2007 January 2010	$150,000,000	4.53%	5.37%
June 2007 December 2009	$150,000,000	4.53%	5.37%
August 2007 February 2010	$250,000,000	4.53%	5.37%
July 2007 January 2010	$250,000,000	4.53%	5.37%

Fair Value of Financial Instruments

The following disclosure of the estimated fair value of financial instruments is made in accordance with the requirements of Statement of Financial Accounting Standards No. 107, *Disclosures About Fair Value of Financial Instruments*. We have determined the estimated fair values by using available market information and valuation methodologies. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value amounts.

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The carrying values of financial instruments comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments. We estimate the fair value of our long-term fixed-rate debt and our convertible preferred stock using primarily quoted market prices. Our carrying amounts for such debt, excluding discounts or premiums related to interest rate derivatives, at September 30, 2006 and December 31, 2005 were $6.421 billion and $5.429 billion, respectively, compared to approximate fair values of $6.317 billion and $5.582 billion, respectively. The carrying amounts for our convertible preferred stock as of September 30, 2006 and December 31, 2005 were $1.962 billion and $1.577 billion, respectively, compared to approximate fair values of $1.950 billion and $1.686 billion, respectively.

Concentration of Credit Risk

A significant portion of our liquidity is concentrated in derivative instruments that enable us to hedge a portion of our exposure to price volatility from producing oil and natural gas. These arrangements expose us to credit risk from our counterparties. Accounts receivable potentially subject us to concentrations of credit risk as well. Our accounts receivable are primarily from purchasers of oil and natural gas products and exploration and production companies which own interests in properties we operate. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

3. Contingencies and Commitments

Litigation

Chesapeake is currently involved in various disputes incidental to its business operations. Management, after consultation with legal counsel, is of the opinion that the final resolution of all currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Employment Agreements with Officers

Chesapeake has employment agreements with its chief executive officer, chief operating officer, chief financial officer and other executive officers, which provide for annual base salaries, various benefits and eligibility for bonus compensation. The agreement with the chief executive officer has a term of five years commencing July 1, 2006. The term of the agreement is automatically extended for one additional year on each January 31 unless the company provides 30 days notice of non-extension. In the event of termination of employment without cause, the chief executive officer s base compensation and benefits would continue during the remaining term of the agreement. The agreements with the chief operating officer, chief financial officer and other executive officers expire on September 30, 2009 and provide for the continuation of salary for one year in the event of termination of employment without cause. The company s employment agreements with the executive officers provide for payments in the event of a change of control. The chief executive officer is entitled to receive a payment in the amount of three times his base compensation and three times the value of the prior year s benefits, plus a tax gross-up payment, upon the happening of certain events following a change of control, and the company will also provide him office space and secretarial and accounting support for a period of 12 months thereafter. The chief operating officer, chief financial officer and other executive officers are each entitled to receive a payment in the amount of two times his or her base compensation plus bonuses paid during the prior year in the event of a change of control. Any stock-based awards held by an executive officer will immediately become 100% vested upon termination of employment without cause or upon a change of control event.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

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Environmental Risk

Due to the nature of the oil and natural gas business, Chesapeake and its subsidiaries are exposed to possible environmental risks. Chesapeake has implemented various policies and procedures to avoid environmental contamination and risks from environmental contamination. Chesapeake conducts periodic reviews, on a company-wide basis, to identify changes in our environmental risk profile. These reviews evaluate whether there is a contingent liability, its amount, and the likelihood that the liability will be incurred. The amount of any potential liability is determined by considering, among other matters, incremental direct costs of any likely remediation and the proportionate cost of employees who are expected to devote a significant amount of time directly to any possible remediation effort. We manage our exposure to environmental liabilities on properties to be acquired by identifying existing problems and assessing the potential liability. Depending on the extent of an identified environmental problem, Chesapeake may exclude a property from the acquisition, require the seller to remediate the property to our satisfaction, or agree to assume liability for the remediation of the property. Chesapeake has historically not experienced any significant environmental liability, and is not aware of any potential material environmental issues or claims at September 30, 2006.

Rig Leases

In September 2006, our wholly owned subsidiary, Nomac Drilling Corporation, sold 18 of its drilling rigs and related equipment for $187.5 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for an initial term of eight years from October 1, 2006 for rental payments of $26.0 million annually. Nomac s lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. This transaction was recorded as a sale and operating leaseback, with an aggregate deferred gain of $14.8 million on the sale which will be amortized to service operations expense over the lease term. Under the rig lease, we have the option to purchase the rigs on September 30, 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

Commitments related to these lease payments are not recorded in the accompanying consolidated balance sheets. As of September 30, 2006, minimum future rig lease payments were as follows (in thousands):

2006	$ 6,130
2007	25,993
2008	25,993
2009	25,993
2010	25,993
Thereafter	97,478
Total	$ 207,580

Other Commitments

As of September 30, 2006, Chesapeake s wholly owned subsidiary, Nomac Drilling Corporation, had contracted to acquire 22 rigs to be constructed during 2006 and 2007. The total remaining cost of the rigs will be approximately $200 million.

Currently, Chesapeake has contracts with various drilling contractors to use approximately 50 rigs in 2006 with terms of one to three years. As of September 30, 2006, the minimum aggregate drilling rig commitment was approximately $450 million.

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Chesapeake and a leading investment bank have an agreement to lend Mountain Drilling Company, of which Chesapeake is a 49% equity owner, up to $25 million each through December 31, 2009. At September 30, 2006, there was a $19.5 million loan outstanding under this agreement.

As of September 30, 2006, Chesapeake had agreed to acquire 16,600 net acres of Barnett Shale leasehold from the Dallas/Fort Worth International Airport Board and the cities of Dallas and Fort Worth for $181 million in cash and a 25% royalty (subject to an assignment of a 20% interest to various minority and women businesses that will participate with Chesapeake in the development of the lease). This transaction closed on October 5, 2006.

As of September 30, 2006, Chesapeake had agreed to acquire oil and natural gas properties and mid-stream natural gas systems from Dale Resources, L.L.C. et al. for approximately $220 million of which $10.9 million was paid in the Current Quarter. This transaction closed on October 12, 2006.

4. Net Income Per Share

Statement of Financial Accounting Standards No. 128, *Earnings Per Share*, requires presentation of basic and diluted earnings per share, as defined, on the face of the statements of operations for all entities with complex capital structures. SFAS 128 requires a reconciliation of the numerator and denominator of the basic and diluted EPS computations.

The following securities were not included in the calculation of diluted earnings per share, as the effect was antidilutive:

For the Current Quarter, Prior Quarter and the Prior Period, outstanding options to purchase 0.1 million shares of common stock at a weighted average exercise price of $30.63, $30.59 and $29.85, respectively, were antidilutive because the exercise price of the options was greater than the average market price of the common stock during the period.

For the Prior Quarter and Prior Period, diluted shares do not include the common stock equivalent of our 4.125% preferred stock outstanding prior to conversion (convertible into 3,913,918 and 8,403,579 shares, respectively), and the preferred stock adjustment to net income does not include $14.7 million and $22.9 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the Prior Quarter and Prior Period, diluted shares do not include the common stock equivalent of our 5.0% (Series 2003) preferred stock outstanding prior to conversion (convertible into 3,603,567 and 4,034,450 shares, respectively), and the preferred stock adjustment to net income does not include $4.0 million and $5.8 million, respectively, of dividends and loss on conversion related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

For the Prior Quarter and the Prior Period, diluted shares do not include the common stock equivalent of our 4.5% preferred stock outstanding prior to conversion (convertible into 1,443,236 and 486,365 shares, respectively), and the preferred stock adjustment to net income does not include $0.7 million and $0.7 million, respectively, of dividends related to these preferred shares, as the effect on diluted earnings per share would have been antidilutive.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reconciliations for the three months ended September 30, 2006 and 2005 and the nine months ended September 30, 2006 and 2005 are as follows:

	Income	Shares	Per Share
For the Three Months Ended September 30, 2006:	**(Numerator)**	**(Denominator)**	**Amount**
	($ in thousands, except per share data)		
Basic EPS:			
Income available to common shareholders	$ 522,582	417,569	$ 1.25
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		184	
Common shares assumed issued for 4.50% convertible preferred stock		7,811	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		235	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		17,856	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		14,717	
Common shares assumed issued for 6.25% convertible preferred stock		19,100	
Employee stock options		4,248	
Restricted stock		1,553	
Preferred stock dividends	25,753		
Diluted EPS Income available to common shareholders and assumed conversions	$ 548,335	483,273	$ 1.13
For the Three Months Ended September 30, 2005:			
Basic EPS:			
Income available to common shareholders	$ 149,059	322,101	$ 0.46
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		8,082	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		6,262	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		17,853	
Common shares assumed issued for 6.00% convertible preferred stock		492	
Employee stock options		11,006	
Restricted stock		1,843	
Preferred stock dividends	8,498		
Diluted EPS Income available to common shareholders and assumed conversions	$ 157,557	367,639	$ 0.43

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

For the Nine Months Ended September 30, 2006:	Income (Numerator)	Shares (Denominator)	Per Share Amount
	($ in thousands, except per share data)		
Basic EPS:			
Income available to common shareholders	$ 1,458,612	389,136	$ 3.75
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		184	
Common shares assumed issued for 4.50% convertible preferred stock		7,811	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		235	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		17,856	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005B)		14,717	
Common shares assumed issued for 6.25% convertible preferred stock		6,498	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion,			
6.00% convertible preferred stock		137	
4.125% convertible preferred stock		2,795	
5.00% convertible preferred stock (Series 2003)		2,807	
Employee stock options		6,714	
Restricted stock		1,790	
Loss on redemption of preferred stock	10,556		
Preferred stock dividends	62,793		
Diluted EPS Income available to common shareholders and assumed conversions	$ 1,531,961	450,680	$ 3.40
For the Nine Months Ended September 30, 2005:			
Basic EPS:			
Income available to common shareholders	$ 447,783	314,425	$ 1.42
Effect of Dilutive Securities			
Assumed conversion as of the beginning of the period of preferred shares outstanding during the period:			
Common shares assumed issued for 4.125% convertible preferred stock		8,082	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2003)		6,262	
Common shares assumed issued for 5.00% convertible preferred stock (Series 2005)		10,739	
Common shares assumed issued for 6.00% convertible preferred stock		492	
Assumed conversion as of the beginning of the period of preferred shares outstanding prior to conversion:			
Common stock equivalent of preferred stock outstanding prior to conversion,			
6.00% convertible preferred stock		5	
Employee stock options		10,810	
Restricted stock		1,382	
Warrants assumed in Gothic acquisition		13	
Preferred stock dividends	18,546		

Diluted EPS Income available to common shareholders and assumed conversions	$ 466,329	352,210	$ 1.32

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Stockholders Equity

The following is a summary of the changes in our common shares outstanding for the nine months ended September 30, 2006 and 2005:

	2006	2005
	(in thousands)	
Shares outstanding at January 1	375,511	316,941
Stock option and warrant exercises	6,676	3,820
Restricted stock issuances	13,530	3,619
Preferred stock conversions/exchanges	12,016	15,804
Common stock issuances	28,750	9,200
Common stock issued for the purchase of Chaparral Energy, Inc. common stock	1,376	
Shares outstanding at September 30	437,859	349,384

The following is a summary of the changes in our preferred shares outstanding for the nine months ended September 30, 2006 and 2005:

	6.00%	5.00% (2003)	4.125%	5.00% (2005)	4.50%	5.00% (2005B)	6.25%
			(in thousands)				
Shares outstanding at January 1, 2006	99	1,026	89	4,600	3,450	5,750	
Preferred stock issuances							2,300
Conversion/exchange of preferred for common stock	(99)	(987)	(86)				
Shares outstanding at September 30, 2006		39	3	4,600	3,450	5,750	2,300
Shares outstanding at January 1, 2005	103	1,725	313				
Preferred stock issuances				4,600	3,450		
Conversion/exchange of preferred for common stock	(2)	(698)	(178)				
Shares outstanding at September 30, 2005	101	1,027	135	4,600	3,450		

In connection with the exchanges and conversions noted above, we recorded a loss of $17.7 million, $10.6 million and $22.5 million in the Prior Quarter, Current Period and Prior Period, respectively. In general, the loss is equal to the excess of the fair value of all common stock exchanged over the fair value of the securities issuable pursuant to the original conversion terms of the preferred stock.

During the Current Period, holders of our 5.0% (Series 2003) cumulative convertible preferred stock exchanged 183,273 shares for 1,140,223 shares of our common stock.

During the Current Period, holders of our 4.125% cumulative convertible preferred stock exchanged 2,750 shares for 172,594 shares of our common stock.

During the Current Period, the remaining 99,310 shares of our 6.0% preferred stock were converted into or exchanged for 482,694 shares of common stock.

During the Current Period, we completed tender offers for our 4.125% and 5.0% (Series 2003) cumulative convertible preferred stock, issuing 5.2 million shares of our common stock in exchange for 83,245 shares of the

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4.125% preferred stock, which represented 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, and 5.0 million shares of our common stock in exchange for 804,048 shares of the 5.0% (Series 2003) preferred stock, which represented 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding. No cash was received or paid in connection with these transactions.

In June 2006, we issued 2,000,000 shares of 6.25% mandatory convertible preferred stock, par value $0.01 per share and liquidation preference $250 per share, in a public offering for net proceeds of $484.8 million. We issued an additional 300,000 shares of such preferred stock in July 2006, upon the exercise of the underwriters option to purchase the additional shares, for net proceeds of $72.8 million.

In June 2006, we issued 25,000,000 shares of Chesapeake common stock at $29.05 per share in a public offering for net proceeds of $698.9 million. We issued an additional 3,750,000 shares in July 2006 at the same price pursuant to the underwriters exercise of their overallotment option to purchase the additional shares for net proceeds of $104.8 million.

In the Current Quarter, we issued 9.9 million shares of restricted stock to our employees (except for our CEO and CFO, who did not participate in the stock awards) under a long-term stock incentive and retention program. These shares vest 50% in three years with the remaining 50% vesting in five years.

In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, with estimated proved reserves of approximately 618 bcfe and daily production of approximately 83 mmcfe.

6. Senior Notes and Revolving Bank Credit Facility

Our long-term debt consisted of the following as of September 30, 2006 and December 31, 2005:

	September 30, 2006	December 31, 2005
	($ in thousands)	
7.5% Senior Notes due 2013	$ 363,823	$ 363,823
7.625% Senior Notes due 2013	500,000	
7.0% Senior Notes due 2014	300,000	300,000
7.5% Senior Notes due 2014	300,000	300,000
7.75% Senior Notes due 2015	300,408	300,408
6.375% Senior Notes due 2015	600,000	600,000
6.625% Senior Notes due 2016	600,000	600,000
6.875% Senior Notes due 2016	670,437	670,437
6.5% Senior Notes due 2017	1,100,000	600,000
6.25% Senior Notes due 2018	600,000	600,000
6.875% Senior Notes due 2020	500,000	500,000
2.75% Contingent Convertible Senior Notes due 2035 (a)	690,000	690,000
Revolving bank credit facility	1,464,000	72,000
Discount on senior notes	(103,939)	(95,577)
Discount for interest rate derivatives (b)	(23,621)	(11,349)
Total senior notes and long-term debt	$ 7,861,108	$ 5,489,742

(a) The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030, or upon a fundamental change, at

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

100% of the principal amount of these notes. The notes are convertible, at the holder s option, prior to maturity under certain circumstances, into cash and, if applicable, shares of our common stock using a net share settlement process. In general, upon conversion of a convertible senior note, the holder will receive cash equal to the principal amount of the note and common stock for the note s conversion value in excess of such principal amount. In addition, we will pay contingent interest on the convertible senior notes, beginning with the nine-month period ending May 14, 2016, under certain conditions. We may redeem the convertible senior notes on or after November 15, 2015 at a redemption price of 100% of the principal amount of such notes.

(b) See Note 2 for a description of these instruments.

No scheduled principal payments are required under our senior notes until 2013 when $863.8 million is due.

There were no repurchases or exchanges of Chesapeake debt in the Current Quarter or the Current Period. The following table sets forth the losses we incurred in connection with repurchases of senior notes in the Prior Quarter and Prior Period, respectively ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Three Months Ended September 30, 2005:	**Retired**	**Premium**	**Other(a)**	**Total**
8.125% Senior Notes due 2011	$ 7.6	$ 0.5	$ 0.1	$ 0.6
9.0% Senior Notes due 2012	1.1	0.1	0.0	0.1
	$ 8.7	$ 0.6	$ 0.1	$ 0.7
For the Nine Months Ended September 30, 2005:				
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 556.4	$ 59.5	$ 10.5	$ 70.0

(a) Includes the write-off of unamortized discounts, deferred charges, transaction costs and derivative charges.

Our outstanding senior notes are unsecured senior obligations of Chesapeake that rank equally in right of payment with all of our existing and future senior indebtedness and rank senior in right of payment to all of our future subordinated indebtedness. We may redeem the senior notes, other than the 2.75% Contingent Convertible Senior Notes due 2035, at any time at specified make-whole or redemption prices. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets.

Chesapeake is a holding company and owns no operating assets and has no significant operations independent of its subsidiaries. Our obligations under our outstanding senior notes have been fully and unconditionally guaranteed, jointly and severally, by all of our wholly owned subsidiaries, other than minor subsidiaries, on a senior unsecured basis.

CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

We have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006 and to $2.5 billion in September 2006. As of September 30, 2006, we had $1.464 billion in outstanding borrowings under our facility and utilized $6.2 million of the facility for various letters of credit. Borrowings under our facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A. or the federal funds effective rate plus 0.50% or (ii) the London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are determined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently, the commitment fee rate is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which govern our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility agreement, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 1.87 to 1 at September 30, 2006. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures, which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility. The facility is fully and unconditionally guaranteed, on a joint and several basis, by Chesapeake and all of our other wholly owned subsidiaries except minor subsidiaries.

7. Segment Information

In accordance with Statement of Financial Accounting Standards No. 131, *Disclosures about Segments of an Enterprise and Related Information*, we have two reportable operating segments. Our exploration and production segment and oil and natural gas marketing segment are managed separately because of the nature of their products and services. The exploration and production segment is responsible for finding and producing natural gas and crude oil. The marketing segment is responsible for gathering, processing, compressing, transporting and selling natural gas and crude oil primarily from Chesapeake-operated wells. We also have drilling rig and trucking operations, which were considered a part of the exploration and production segment prior to 2006. These service operations are responsible for providing drilling rigs primarily used on Chesapeake-operated wells and trucking services utilized in the transportation of drilling rigs on both Chesapeake-operated wells and wells operated by third parties.

Management evaluates the performance of our segments based upon income before income taxes. Revenues from the marketing segment s sale of oil and natural gas related to Chesapeake s ownership interests are reflected as exploration and production revenues. Such amounts totaled $631.0 million, $617.4 million, $1.919 billion and

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

$1.486 billion for the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. The following table presents selected financial information for Chesapeake s operating segments. Our drilling rig and trucking service operations are presented in Other Operations for all periods presented.

	Exploration and Production	Marketing	Other Operations ($ in thousands)	Intercompany Eliminations	Consolidated Total
For the Three Months Ended September 30, 2006:					
Revenues	$ 1,493,226	$ 1,029,126	$ 98,401	$ (691,342)	$ 1,929,411
Intersegment revenues		(631,012)	(60,330)	691,342	
Total revenues	$ 1,493,226	$ 398,114	$ 38,071	$	$ 1,929,411
Income before income taxes	$ 866,789	$ 9,661	$ 33,900	$ (25,941)	$ 884,409
For the Three Months Ended September 30, 2005:					
Revenues	$ 720,928	$ 979,281	$ 16,405	$ (633,771)	$ 1,082,843
Intersegment revenues		(617,366)	(16,405)	633,771	
Total revenues	$ 720,928	$ 361,915	$	$	$ 1,082,843
Income before income taxes	$ 271,835	$ 6,887	$ 1,823	$ (1,823)	$ 278,722
For the Nine Months Ended September 30, 2006:					
Revenues	$ 4,190,430	$ 3,089,348	$ 218,909	$ (2,040,693)	$ 5,457,994
Intersegment revenues		(1,919,257)	(121,436)	2,040,693	
Total revenues	$ 4,190,430	$ 1,170,091	$ 97,473	$	$ 5,457,994
Income before income taxes	$ 2,448,286	$ 29,099	$ 67,653	$ (49,941)	$ 2,495,097
For the Nine Months Ended September 30, 2005:					
Revenues	$ 2,032,271	$ 2,368,502	$ 39,587	$ (1,526,049)	$ 2,914,311
Intersegment revenues		(1,486,462)	(39,587)	1,526,049	
Total revenues	$ 2,032,271	$ 882,040	$	$	$ 2,914,311
Income before income taxes	$ 764,200	$ 16,554	$ 4,638	$ (4,638)	$ 780,754
As of September 30, 2006:					
Total assets	$ 22,669,668	$ 667,399	$ 532,414	$ (474,560)	$ 23,394,921
As of December 31, 2005:					
Total assets	$ 15,722,795	$ 688,747	$ 305,875	$ (598,955)	$ 16,118,462

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Acquisitions

Oil and Natural Gas Properties

The following table describes oil and natural gas property acquisitions of proved and unproved properties that we completed in the Current Period ($ in millions):

Quarter	Acquired From	Location of Properties	Amount
First	Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
	Tulsa-based oil and gas company	Texas Gulf Coast and Mid-Continent	146
	Houston-based oil and gas company	Texas Gulf Coast	125
	Tulsa-based oil and gas company	Ark-La-Tex	70
	Houston-based oil and gas company	Various	53
	Dallas-based oil and gas company	Mid-Continent	30
	Other	Various	297
Second	Dallas-based oil and gas company	Permian	375
	Oklahoma City-based oil and gas company	Permian	175
	Other	Various	196
Third	Four Sevens Oil Co., Ltd. and Sinclair Oil Corporation	Barnett Shale	845(a)
	Dallas-based oil and gas company	Ark-La-Tex and Texas Gulf Coast	200
	Houston-based oil and gas company	Texas Gulf Coast	111
	Other	Various	285
	Total oil and natural gas acquisitions		$ 3,180

(a) Includes $55 million related to mid-stream natural gas systems which was allocated to other property and equipment.

We also recorded approximately $177.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

Drilling Rigs and Oilfield Trucks

In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. In addition to the cash purchase price, we recorded approximately $17.0 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. Of the total $64.5 million purchase price, $27.1 million was allocated to tangible equipment, $11.0 million to intangibles and $26.4 million to goodwill. The amounts allocated to intangibles and goodwill are included in long-term assets in the accompanying condensed consolidated balance sheet. Goodwill is not amortized but is subject to an annual assessment of impairment. In February 2006, we acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for $150 million. In July 2006, we acquired a drilling contractor and an affiliated trucking company in the Appalachian Basin for approximately $70 million in cash.

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CHESAPEAKE ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Other

In August 2006, we invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, with estimated proved reserves of approximately 618 bcfe and daily production of 83 mmcfe.

9. Full-Cost Ceiling Test

We review the carrying value of our oil and natural gas properties under the full-cost accounting rules of the Securities and Exchange Commission (SEC) on a quarterly and annual basis. This review is referred to as a ceiling test. Under the ceiling test, capitalized costs, less accumulated amortization and related deferred income taxes, may not exceed an amount equal to the sum of the present value of estimated future net revenues (including the impact of cash flow hedges) less estimated future expenditures to be incurred in developing and producing the proved reserves, less any related income tax effects. The two primary factors impacting this test are reserve levels and current prices, and their associated impact on the present value of estimated future net revenues. Revisions to the estimates of natural gas and oil reserves and/or an increase or decrease in prices can have a material impact on the present value of estimated future net revenues. Any excess of the net book value, less deferred income taxes, is generally written off as an expense. Under SEC regulations, the excess above the ceiling is not expensed (or is reduced) if, subsequent to the end of the period, but prior to the release of the financial statements, oil and natural gas prices increase sufficiently such that an excess above the ceiling would have been eliminated (or reduced) if the increased prices were used in the calculations.

In calculating future net revenues, current prices and costs used are those as of the end of the appropriate quarterly period. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts, including the effects of derivatives qualifying as cash flow hedges. Such derivative contracts, which consist of swaps and collars, and the related production volumes are discussed in Note 2 and in Item 3. *Quantitative and Qualitative Disclosures About Market Risk*. Based on spot prices for oil and natural gas as of September 30, 2006, these cash flow hedges increased the full cost ceiling by $4.4 billion, thereby reducing any potential ceiling test write-down by the same amount.

At December 31, 2005, Chesapeake s net book value of oil and natural gas properties less deferred income taxes was below the calculated ceiling by approximately $6.5 billion. From December 31, 2005 to September 30, 2006, spot natural gas prices decreased by approximately 59% from $10.08 to $4.18 per mcf. As a result, as of September 30, 2006, our ceiling test calculation indicated an impairment of our oil and natural gas properties of approximately $415 million, net of income tax. However, natural gas prices subsequent to September 30, 2006, have improved sufficiently to eliminate this calculated impairment. As a result, we were not required to record a write-down of our oil and natural gas properties under the full-cost method of accounting in the third quarter of 2006.

10. Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In December 2004, the FASB issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, *Accounting for Stock-Based Compensation*. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 did not have a material impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. We are currently evaluating the provisions of SFAS 155 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact, if any, SFAS 157 will have on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans. This statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement is effective as of the end of the fiscal year ending after December 15, 2006. We do not expect that SFAS 158 will have a material impact on our financial position, results of operations or cash flows.

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

Overview

The following table sets forth certain information regarding the production volumes, oil and natural gas sales, average sales prices received, other operating income and expenses for the three and nine months ended September 30, 2006 (the Current Quarter and the Current Period) and the three and nine months ended September 30, 2005 (the Prior Quarter and the Prior Period):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	**2005**	**2006**	**2005**
Net Production:				
Oil (mbbls)	2,178	1,926	6,437	5,684
Natural gas (mmcf)	133,822	108,801	387,696	304,060
Natural gas equivalent (mmcfe)	146,890	120,357	426,318	338,164
Oil and Natural Gas Sales ($ in thousands):				
Oil sales	$ 141,687	$ 113,590	$ 404,595	$ 290,332
Oil derivatives realized gains (losses)	(9,660)	(10,937)	(25,695)	(28,654)
Oil derivatives unrealized gains (losses)	28,724	(4,009)	24,825	(5,951)
Total oil sales	160,751	98,644	403,725	255,727
Natural gas sales	811,591	833,992	2,526,168	2,005,670
Natural gas derivatives realized gains (losses)	311,090	(111,668)	832,769	(97,955)
Natural gas derivatives unrealized gains (losses)	209,794	(100,040)	427,768	(131,171)
Total natural gas sales	1,332,475	622,284	3,786,705	1,776,544
Total oil and natural gas sales	$ 1,493,226	$ 720,928	$ 4,190,430	$ 2,032,271
Average Sales Price (excluding all gains (losses) on derivatives):				
Oil ($ per bbl)	$ 65.05	$ 58.98	$ 62.85	$ 51.08
Natural gas ($ per mcf)	$ 6.06	$ 7.67	$ 6.52	$ 6.60
Natural gas equivalent ($ per mcfe)	$ 6.49	$ 7.87	$ 6.87	$ 6.79
Average Sales Price (excluding unrealized gains (losses) on derivatives):				
Oil ($ per bbl)	$ 60.62	$ 53.30	$ 58.86	$ 46.04
Natural gas ($ per mcf)	$ 8.39	$ 6.64	$ 8.66	$ 6.27
Natural gas equivalent ($ per mcfe)	$ 8.54	$ 6.85	$ 8.77	$ 6.42
Other Operating Income (a) ($ in thousands):				
Oil and natural gas marketing	$ 13,641	$ 8,405	$ 38,570	$ 21,251
Service operations	$ 19,250	$	$ 48,548	$
Other Operating Income ($ per mcfe):				
Oil and natural gas marketing	$ 0.09	$ 0.07	$ 0.09	$ 0.06
Service operations	$ 0.13	$	$ 0.11	$
Expenses ($ per mcfe):				
Production expenses	$ 0.84	$ 0.67	$ 0.85	$ 0.66
Production taxes	$ 0.28	$ 0.44	$ 0.30	$ 0.40
General and administrative expenses	$ 0.25	$ 0.13	$ 0.23	$ 0.12
Oil and natural gas depreciation, depletion and amortization	$ 2.34	$ 1.92	$ 2.29	$ 1.84
Depreciation and amortization of other assets	$ 0.18	$ 0.11	$ 0.17	$ 0.10
Interest expense (b)	$ 0.52	$ 0.48	$ 0.52	$ 0.47
Interest Expense ($ in thousands):				
Interest expense	$ 75,100	$ 58,206	$ 221,832	$ 160,209
Interest rate derivatives realized (gains) losses	1,555	(843)	(852)	(2,639)
Interest rate derivatives unrealized (gains) losses	(2,543)	1,230	(754)	(1,947)

Total interest expense	$ 74,112	$ 58,593	$ 220,226	$ 155,623
Net Wells Drilled	401	218	985	583
Net Producing Wells as of the End of the Period	18,511	9,313	18,511	9,313

(a) Includes revenue and operating costs.

(b) Includes the effects of realized gains (losses) from interest rate derivatives, but does not include the effects of unrealized gains (losses) and is net of amounts capitalized.

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Chesapeake is the third largest independent producer of natural gas in the United States. We own interests in approximately 33,700 producing oil and natural gas wells that are currently producing approximately 1.66 bcfe per day, which includes approximately 0.1 bcfe per day of previously curtailed production that is now back on line. Our strategy is focused on discovering, developing and acquiring onshore natural gas reserves in the U.S. east of the Rocky Mountains. Our most important operating area has historically been in various conventional plays in the Mid-Continent region, which includes Oklahoma, Arkansas, Kansas and the Texas Panhandle. At September 30, 2006, 47% of our estimated proved oil and natural gas reserves were located in the Mid-Continent. During the past four years, we have also built significant positions in various conventional and unconventional plays in the South Texas and Texas Gulf Coast regions, the Permian Basin of West Texas and eastern New Mexico, the Barnett Shale area of North Texas, the Ark-La-Tex area of East Texas and northern Louisiana, the Appalachian Basin in West Virginia, eastern Kentucky, eastern Ohio and southern New York, the Caney and Woodford Shales in southeastern Oklahoma, the Fayetteville Shale in Arkansas, the Barnett and Woodford Shales in West Texas and the Conasauga, Floyd and Chattanooga Shales of Alabama.

Oil and natural gas production for the Current Quarter was 146.9 bcfe, an increase of 26.5 bcfe, or 22% over the 120.4 bcfe produced in the Prior Quarter. We have increased our production for 21 consecutive quarters. During these 21 quarters, Chesapeake s U.S. production has increased 308% for an average compound quarterly growth rate of 6.9% and an average compound annual growth rate of 30.5%.

In addition to increased oil and natural gas production, the prices we received were higher in the Current Quarter than in the Prior Quarter. On a natural gas equivalent basis, weighted average prices (excluding the effect of unrealized gains or losses on derivatives) were $8.54 per mcfe in the Current Quarter compared to $6.85 per mcfe in the Prior Quarter. The increase in prices resulted in an increase in revenue of $247.9 million, and increased production resulted in an increase in revenue of $181.8 million, for a total increase in revenue of $429.7 million (excluding the effect of unrealized gains or losses on derivatives). In each of the operating areas where Chesapeake sells its oil and natural gas, established marketing and transportation infrastructures exist, thereby contributing to relatively high wellhead price realizations for our production.

During the Current Quarter, Chesapeake continued to lead the nation in drilling activity with an average utilization of 103 operated rigs and 71 non-operated rigs. Through this drilling activity, we drilled 411 (348 net) operated wells and participated in another 353 (53 net) wells operated by other companies. The company s drilling success rate was 99% for company-operated wells and 96% for non-operated wells. During the Current Quarter, Chesapeake invested $674 million in operated wells, $119 million in non-operated wells and $162 million in acquiring 3-D seismic data and leasehold (excluding leasehold acquired through acquisitions). Our acquisition expenditures totaled $1.391 billion during the Current Quarter, including amounts paid for unproved leasehold and excluding $96.3 million of deferred income taxes in connection with certain corporate acquisitions. We expect to continue replacing reserves through the drillbit and acquisitions, although the timing and magnitude of future additions are uncertain.

Chesapeake began 2006 with estimated proved reserves of 7.521 tcfe and based on internal estimates ended the Current Quarter with 8.433 tcfe, an increase of 912 bcfe, or 12%. During the Current Period, we replaced 426 bcfe of production with an estimated 1.339 tcfe of new proved reserves, for a reserve replacement rate of 314%. Reserve replacement through the drillbit was 825 bcfe, or 194% of production (including 541 bcfe of positive performance revisions and 387 bcfe of downward revisions resulting from natural gas price declines between December 31, 2005 and September 30, 2006) and 62% of the total increase. Reserve replacement through the acquisition of proved reserves was 514 bcfe, or 120% of production and 38% of the total increase. Based on our current drilling schedule and budget, we expect that virtually all of the proved undeveloped reserves added in 2006 will begin producing within the next three to five years. Generally, proved developed reserves are producing at the time they are added or will begin producing within one year.

Chesapeake attributes its strong drilling results and organic growth rates during the first nine months of 2006 (and in this decade) to management s early recognition that oil and natural gas prices were undergoing structural change and its subsequent decision to invest aggressively in the building blocks of value creation in the E&P industry people, land and seismic. During the past five years, Chesapeake has significantly strengthened its technical capabilities by increasing its land, geoscience and engineering staff to approximately 800 employees. Today, the company has more than 4,600 employees, of which approximately 65% work in the company s E&P operations and 35% work in the company s oilfield service operations.

Since 2000, Chesapeake has invested $5.7 billion in new leasehold and 3-D seismic acquisitions and now owns what it believes to be one of the largest inventories of onshore leasehold (10.5 million net acres) and 3-D seismic (14.7 million acres) in the U.S. On this leasehold, the company has an estimated 25,000 net drilling locations representing an approximate 10-year inventory of drilling projects.

To further hedge its exposure to oilfield service costs and achieve greater operational efficiency, Chesapeake has recently invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. It also has expansion efforts underway in many other key regions in which Chesapeake operates.

This investment complements Chesapeake s direct and indirect drilling rig investments that have served as an effective hedge to higher service costs and have also provided competitive advantages in making acquisitions and in developing the company s own leasehold on a more timely and efficient basis. To date, Chesapeake has invested approximately $254 million to build or acquire 42 drilling rigs and is building 22 additional rigs. Additionally, the company entered into a sale/leaseback transaction to monetize its investment in 18 of its rigs in exchange for cash proceeds of $187.5 million. These rigs are under lease to Chesapeake through 2014 at which time the company has the option to reacquire them. In total, the company s drilling rig fleet should reach 82 rigs by mid-year 2007, which would rank Chesapeake as the sixth largest drilling rig contractor in the U.S. Additionally, the company has a $69 million investment in two private drilling rig contractors, DHS Drilling Company and Mountain Drilling Company, in which Chesapeake s equity ownership is approximately 45% and 49%, respectively. DHS owns 16 rigs and Mountain is operating two rigs and has another eight rigs under construction or on order for delivery in 2006 and 2007.

As of September 30, 2006, the company s debt as a percentage of total capitalization (total capitalization is the sum of debt and stockholders equity) was 44% compared to 47% as of December 31, 2005. During the Current Period, we received net proceeds of $2.3 billion through issuances of $575 million of preferred equity, $835 million of common equity and $1.0 billion principal amount of senior notes. We used the net proceeds from these offerings primarily to fund the purchase price for acquisitions and to repay outstanding indebtedness under our revolving bank credit facility. As a result of our debt transactions in 2005 and the Current Period, we have extended the average maturity of our long-term debt to over nine years and have lowered our average interest rate to approximately 6.4%.

We intend to continue to focus on improving the strength of our balance sheet. We believe our business strategy and operational performance will lead to an investment grade credit rating for our unsecured debt at some point in the future.

Liquidity and Capital Resources

Sources and Uses of Funds

Our primary source of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions) is cash flow from operations. Based on our current production, price and expense assumptions, we expect cash flow from operations will exceed our drilling capital expenditures for the remainder of 2006 and 2007. Our budget for drilling, land and seismic activities for the remainder of 2006 is currently between $1.1 billion and $1.3 billion. We believe this level of exploration and development will be sufficient to increase our proved oil and natural gas reserves in 2006 and achieve our goal of an organic growth rate of more than 10% over 2005 production and at least a 23% increase in total production (inclusive of acquisitions completed or scheduled to close in 2006 through the filing date of this report but without regard to any additional acquisitions that may be completed in 2006). However, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions, prolonged shut-ins or other factors could cause us to revise our drilling program, which is largely discretionary. Any cash flow from operations not needed to fund our drilling program will be available for acquisitions, debt repayment or other general corporate purposes.

Cash provided by operating activities was $2.982 billion in the Current Period compared to $1.577 billion in the Prior Period. The $1.405 billion increase was primarily due to higher realized prices and higher oil and natural gas production. While a further decline in natural gas prices for the remainder of 2006 and 2007 would affect the amount of cash flow that would be generated from operations, we have 88% and 73% of our expected oil production for the fourth quarter of 2006 and 2007, respectively, hedged at an average NYMEX price of $65.64 and $71.42 per barrel of oil, respectively, and 57% of our expected natural gas production for both the fourth quarter of 2006 and 2007, respectively, hedged at an average NYMEX price of $9.10 and $9.61 per mmbtu, respectively. These levels of hedging provide greater certainty of the cash flow we will receive for a substantial portion of our remaining 2006 and 2007 production. Depending on changes in oil and natural gas futures markets and management s view of underlying oil and natural gas supply and demand trends, however, we may increase or decrease our current hedging positions.

Based on fluctuations in natural gas and oil prices, our hedging counterparties may require us to deliver cash collateral or other assurances of performance from time to time. All but two of our commodity price risk management counterparties require us to provide assurances of performance in the event that the counterparties mark-to-market exposure to us exceeds certain levels. Most of these arrangements allow us to minimize the potential liquidity impact of significant mark-to-market fluctuations by making collateral allocations from our bank credit facility or directly pledging oil and natural gas properties, rather than posting cash or letters of credit with the counterparties. As of September 30, 2006, we had outstanding collateral allocations and pledges of oil and gas properties, with respect to commodity price risk management transactions but were not required to post any collateral with our counterparties through letters of credit issued under our bank credit facility. As of November 3, 2006, we had outstanding transactions with thirteen counterparties, seven of which hold collateral allocations from our bank facility or liens against certain oil and natural gas properties under our secured hedging facilities, and two of which do not require us to provide security for our risk management transactions. As of November 3, 2006, we were not required to post cash or letters of credit with the remaining four counterparties. Future collateral requirements are uncertain and will depend on the arrangements with our counterparties and highly volatile natural gas and oil prices.

A significant source of liquidity is our $2.5 billion syndicated revolving bank credit facility which matures in February 2011. At November 3, 2006, there was $749.8 million of borrowing capacity available under the revolving bank credit facility. We use the facility to fund daily operating activities and acquisitions as needed. We borrowed $7.058 billion and repaid $5.666 billion in the Current Period, and we borrowed $3.561 billion and repaid $3.620 billion in the Prior Period under the credit facility. We incurred $5.1 million and $4.7 million of financing costs related to amendments to the credit facility agreement in the Current Period and the Prior Period, respectively.

We believe that our available cash, cash provided by operating activities and funds available under our revolving bank credit facility will be sufficient to fund our operating, debt service and general and administrative expenses, our capital expenditure budget, our short-term contractual obligations and dividend payments at current levels for the foreseeable future.

The public and institutional markets have been our principal source of long-term financing for acquisitions. We have sold debt and equity in both public and private offerings in the past, and we expect that these sources of capital will continue to be available to us in the future to finance acquisitions. Nevertheless, we caution that ready access to capital on reasonable terms and the availability of desirable acquisition targets at attractive prices are subject to many uncertainties, as explained under Risk Factors in Item 1A of our Form 10-K for the year ended December 31, 2005.

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The following table reflects the proceeds from sales of securities we issued in the Current Period and the Prior Period ($ in millions):

	For the Nine Months Ended September 30, 2006		2005	
	Total Proceeds	Net Proceeds	Total Proceeds	Net Proceeds
Convertible preferred stock	$ 575.0	$ 557.6	$ 805.0	$ 782.4
Common stock	835.2	803.7	301.0	289.4
Unsecured senior notes guaranteed by subsidiaries	1,000.0	969.2	1,800.0	1,765.4
Total	$ 2,410.2	$ 2,330.5	$ 2,906.0	$ 2,837.2

We qualify as a well-known seasoned issuer (WKSI), as defined in Rule 405 of the Securities Act of 1933, and therefore we may utilize automatic shelf registration to register future debt and equity issuances with the Securities and Exchange Commission. A prospectus supplement will be prepared at the time of an offering and will contain a description of the security issued, the plan of distribution and other information.

We paid dividends on our common stock of $61.8 million and $45.8 million in the Current Period and the Prior Period, respectively. The board of directors increased the quarterly dividend on common stock from $0.05 to $0.06 per share beginning with the dividend paid in July 2006. We paid dividends on our preferred stock of $62.5 million and $17.3 million in the Current Period and the Prior Period, respectively. We received $71.3 million and $19.9 million from the exercise of employee and director stock options and warrants in the Current Period and the Prior Period, respectively. The Current Period amount included $38.3 million paid by Tom L. Ward, our former President and Chief Operating Officer, to exercise all of his stock options following his resignation in February 2006.

In the Current Period, we paid $68.4 million to settle a portion of the derivative liabilities assumed in our November 2005 acquisition of Columbia Natural Resources, LLC.

On January 1, 2006, we adopted SFAS 123(R), which requires tax benefits resulting from stock-based compensation deductions in excess of amounts reported for financial reporting purposes to be reported as cash flows from financing activities. In the Current Period, we reported a tax benefit from stock-based compensation of $85.6 million.

Outstanding payments from certain disbursement accounts in excess of funded cash balances where no legal right of set-off exists increased by $43.3 million and $33.8 million in the Current Period and the Prior Period, respectively. All disbursements are funded on the day they are presented to our bank using available cash on hand or draws on our revolving bank credit facility.

Historically, we have used significant funds to redeem or purchase and retire outstanding senior notes issued by Chesapeake. The following table shows our purchases and exchanges of senior notes in the Prior Period ($ in millions):

	Senior Notes Activity			
For the Nine Months Ended September 30, 2005:	Retired	Premium	Other(a)	Cash Paid
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$	$ 11.8
8.125% Senior Notes due 2011	245.4	17.3	0.7	263.4
9.0% Senior Notes due 2012	300.0	41.4	0.8	342.2
	$ 556.4	$ 59.5	$ 1.5	$ 617.4

(a) Includes adjustments to accrued interest and discount associated with notes retired and new notes issued, cash in lieu of fractional notes, transaction costs and fair value hedging adjustments.

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Cash used in investing activities increased to $6.668 billion during the Current Period, compared to $3.655 billion during the Prior Period. The following table shows our cash used in (provided by) investing activities during these periods ($ in millions):

	Nine Months Ended September 30,	
	2006	**2005**
Oil and Natural Gas Investing Activities:		
Acquisitions of oil and natural gas companies and proved properties, net of cash acquired	$ 960.8	$ 1,175.3
Acquisition of unproved properties	2,128.9	757.6
Exploration and development of oil and natural gas properties	2,041.8	1,294.6
Leasehold acquisitions	456.2	164.6
Geological and geophysical costs	101.8	44.3
Other oil and natural gas activities	(16.0)	(15.4)
Total oil and natural gas investing activities	5,673.5	3,421.0
Other Investing Activities:		
Additions to buildings and other fixed assets	406.8	157.0
Additions to drilling rig equipment (including Martex Drilling Company, L.L.P)	340.8	42.1
Additions to investments	537.7	37.3
Proceeds from sale of investment in Pioneer Drilling Company	(158.9)	
Proceeds from sale of drilling rigs and equipment	(187.5)	
Acquisition of trucking company, net of cash acquired	45.2	
Deposits for acquisitions	12.1	
Other	(1.7)	(2.4)
Total other investing activities	994.5	234.0
Total cash used in (provided by) investing activities	$ 6,668.0	$ 3,655.0

Our accounts receivable are primarily from purchasers of oil and natural gas ($499.0 million at September 30, 2006) and exploration and production companies which own interests in properties we operate ($115.0 million at September 30, 2006). This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic, industry or other conditions. We generally require letters of credit for receivables from customers which are judged to have sub-standard credit, unless the credit risk can otherwise be mitigated.

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Acquisitions and Financing Transactions

The following table describes investing transactions related to the acquisition of proved and unproved properties that we completed in the Current Period ($ in millions):

Quarter	Acquired From	Location of Properties	Amount
First	Midland-based oil and gas company	Ark-La-Tex and Barnett Shale	$ 272
	Tulsa-based oil and gas company	Texas Gulf Coast and Mid-Continent	146
	Houston-based oil and gas company	Texas Gulf Coast	125
	Tulsa-based oil and gas company	Ark-La-Tex	70
	Houston-based oil and gas company	Various	53
	Dallas-based oil and gas company	Mid-Continent	30
	Other	Various	297
Second	Dallas-based oil and gas company	Permian	375
	Oklahoma City-based oil and gas company	Permian	175
	Other	Various	196
Third	Four Sevens Oil Co., Ltd. and Sinclair Oil Corporation	Barnett Shale	845(a)
	Dallas-based oil and gas company	Ark-La-Tex and Texas Gulf Coast	200
	Houston-based oil and gas company	Texas Gulf Coast	111
	Other	Various	285
	Total oil and natural gas acquisitions		3,180
	Less cash deposits paid in 2005		(35)
	Total oil and natural gas acquisitions in the Current Period		$ 3,145

(a) Includes $55 million related to mid-stream natural gas systems which was allocated to other property and equipment.

We also recorded approximately $177.7 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired on certain corporate acquisitions.

In January 2006, we acquired a privately-owned Oklahoma-based oilfield trucking service company for $47.5 million. We recorded approximately $17.0 million of deferred income taxes to reflect the tax effect of the cost paid in excess of the tax basis acquired in connection with this acquisition. In February 2006, we acquired 13 drilling rigs and related assets through our wholly-owned subsidiary, Nomac Drilling Corporation, from Martex Drilling Company, L.L.P., a privately-owned drilling contractor with operations in East Texas and North Louisiana, for $150 million. In July 2006, we acquired a drilling contractor and an affiliated trucking company in the Appalachian Basin for approximately $70 million in cash.

In August 2006, we invested $254 million to acquire a 19.9% interest in a privately-held provider of well stimulation and high pressure pumping services, with operations currently focused in Texas (principally in the Fort Worth Barnett Shale) and the Rocky Mountains. In September 2006, we acquired 32% of the outstanding common stock of Chaparral Energy, Inc. for $240 million in cash and 1,375,989 newly issued shares of our common stock valued at $40 million. Chaparral is a privately-held independent oil and natural gas company headquartered in Oklahoma City, Oklahoma, with estimated proved reserves of approximately 618 bcfe and daily production of approximately 83 mmcfe.

During 2005 and continuing in 2006, we have taken several steps to improve our capital structure. These transactions enabled us to extend our average maturity of long-term debt to over nine years with an average interest rate of approximately 6.4%. Maintaining a debt-to-total-capitalization ratio of below 50% and reducing debt per mcfe of proved reserves remain key goals of our business strategy.

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We completed the following significant financing transactions in the Current Period:

First Quarter 2006

- Amended and restated our revolving bank credit facility, increasing the commitments to $2.0 billion and extending the maturity date to February 2011.
- Issued an additional $500 million of our 6.5% Senior Notes due 2017 in a private placement and used the proceeds of approximately $487 million to repay outstanding borrowings under our revolving bank credit facility incurred primarily to fund our recent acquisitions.

Second Quarter 2006

- Completed a public exchange of 83,245 shares of our 4.125% cumulative convertible preferred stock, representing 96.4% or $83.2 million of the aggregate liquidation value of the shares outstanding, for 5.2 million shares of our common stock pursuant to a tender offer. No cash was received or paid in connection with this transaction.
- Completed a public exchange of 804,048 shares of our 5.0% (Series 2003) cumulative convertible preferred stock, representing 95.4% or $80.4 million of the aggregate liquidation value of the shares outstanding, for 5.0 million shares of our common stock pursuant to a tender offer. No cash was received or paid in connection with this transaction.
- Completed public offerings of $500 million of 7.625% Senior Notes due 2013, 2.0 million shares of 6.25% mandatory convertible preferred stock having a liquidation preference of $250 per share, and 25 million shares of common stock at $29.05 per share. Net proceeds of approximately $1.666 billion were used to fund acquisitions, to repay borrowings under our revolving bank credit facility and for general corporate purposes.

Third Quarter 2006

- Increased the commitments under our revolving bank credit facility to $2.5 billion.
- Issued 3.75 million shares of common stock at $29.05 per share and 300,000 shares of our 6.25% mandatory convertible preferred stock having a liquidation preference of $250 per share upon the exercise of the underwriters options to purchase the additional shares pursuant to the June 2006 public offerings of our common stock and 6.25% preferred stock. Net proceeds of approximately $177.6 million were used to repay borrowings under our revolving bank credit facility.

Contractual Obligations

We currently have a $2.5 billion syndicated revolving bank credit facility which matures in February 2011. The credit facility was increased from $1.25 billion to $2.0 billion in February 2006 and to $2.5 billion in September 2006. As of September 30, 2006, we had $1.464 billion in outstanding borrowings under this facility and had utilized $6.2 million of the facility for various letters of credit. Borrowings under the facility are collateralized by certain producing oil and natural gas properties and bear interest at either (i) the greater of the reference rate of Union Bank of California, N.A., or the federal funds effective rate plus 0.50% or (ii) London Interbank Offered Rate (LIBOR), at our option, plus a margin that varies from 0.875% to 1.50% per annum according to our senior unsecured long-term debt ratings. The collateral value and borrowing base are redetermined periodically. The unused portion of the facility is subject to a commitment fee that also varies according to our senior unsecured long-term debt ratings, from 0.125% to 0.30% per annum. Currently the commitment fee is 0.25% per annum. Interest is payable quarterly or, if LIBOR applies, it may be payable at more frequent intervals.

The credit facility agreement contains various covenants and restrictive provisions which limit our ability to incur additional indebtedness, make investments or loans and create liens. The credit facility agreement requires

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us to maintain an indebtedness to total capitalization ratio (as defined) not to exceed 0.65 to 1 and an indebtedness to EBITDA ratio (as defined) not to exceed 3.5 to 1. As defined by the credit facility, our indebtedness to total capitalization ratio was 0.44 to 1 and our indebtedness to EBITDA ratio was 1.87 to 1 at September 30, 2006. If we should fail to perform our obligations under these and other covenants, the revolving credit commitment could be terminated and any outstanding borrowings under the facility could be declared immediately due and payable. Such acceleration, if involving a principal amount of $10 million ($50 million in the case of our senior notes issued after 2004), would constitute an event of default under our senior note indentures which could in turn result in the acceleration of a significant portion of our senior note indebtedness. The credit facility agreement also has cross default provisions that apply to other indebtedness we may have with an outstanding principal amount in excess of $75 million.

We also have two secured hedging facilities, each of which permits us to enter into cash-settled natural gas and oil commodity transactions, valued by the counterparty, for up to $500 million. The scheduled maturity date for these facilities is May 2010. Outstanding transactions under each facility are collateralized by certain of our oil and natural gas properties that do not secure any of our other obligations. The hedging facilities are subject to a 1.0% per annum exposure fee, which is assessed quarterly on the average of the daily negative fair market value amounts, if any, during the quarter. As of September 30, 2006, the fair market value of the natural gas and oil hedging transactions was an asset of $252.1 million under one of the facilities and an asset of $823.2 million under the other facility. As of November 3, 2006, the fair market value of the same transactions was an asset of approximately $152.2 million and $255.5 million, respectively. The hedging facilities contain the standard representations and default provisions that are typical of such agreements. The agreements also contain various restrictive provisions which govern the aggregate oil and natural gas production volumes that we are permitted to hedge under all of our agreements at any one time.

Two of our subsidiaries, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., are the borrowers under our revolving bank credit facility and Chesapeake Exploration Limited Partnership is the named party to our hedging facilities. The facilities are guaranteed by Chesapeake and all its other wholly-owned subsidiaries except minor subsidiaries. Our revolving bank credit facility and secured hedging facilities do not contain material adverse change or adequate assurance covenants. Although the applicable interest rates and commitment fees in our bank credit facility fluctuate slightly based on our long-term senior unsecured credit ratings, the bank facility and the secured hedging facilities do not contain provisions which would trigger an acceleration of amounts due under the facilities or a requirement to post additional collateral in the event of a downgrade of our credit ratings.

As of September 30, 2006, our senior notes consisted of the following ($ in thousands):

7.5% Senior Notes due 2013	$ 363,823
7.625% Senior Notes due 2013	500,000
7.0% Senior Notes due 2014	300,000
7.5% Senior Notes due 2014	300,000
7.75% Senior Notes due 2015	300,408
6.375% Senior Notes due 2015	600,000
6.625% Senior Notes due 2016	600,000
6.875% Senior Notes due 2016	670,437
6.5% Senior Notes due 2017	1,100,000
6.25% Senior Notes due 2018	600,000
6.875% Senior Notes due 2020	500,000
2.75% Contingent Convertible Senior Notes due 2035	690,000
Discount on senior notes	(103,939)
Discount for interest rate derivatives	(23,621)
	$ 6,397,108

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No scheduled principal payments are required under our senior notes until 2013, when $863.8 million is due. The holders of the 2.75% Contingent Convertible Senior Notes due 2035 may require us to repurchase all or a portion of these notes on November 15, 2015, 2020, 2025 and 2030 at 100% of the principal amount of these notes.

As of September 30, 2006 and currently, debt ratings for the senior notes are Ba2 by Moody s Investor Service (stable outlook), BB by Standard & Poor s Ratings Services (stable outlook) and BB by Fitch Ratings.

Our senior notes are unsecured senior obligations of Chesapeake and rank equally in right of payment with all of our other existing and future senior indebtedness and rank senior in right of payment with all of our future subordinated indebtedness. All of our wholly-owned subsidiaries, except minor subsidiaries, fully and unconditionally guarantee the notes jointly and severally on an unsecured basis. Senior notes issued before July 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur additional indebtedness; pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness; make investments and other restricted payments; incur liens; enter into sale-leaseback transactions; create restrictions on the payment of dividends or other amounts to us from our restricted subsidiaries; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. Senior notes issued after June 2005 are governed by indentures containing covenants that limit our ability and our restricted subsidiaries ability to incur certain secured indebtedness; enter into sale-leaseback transactions; and consolidate, merge or transfer assets. The debt incurrence covenants do not presently restrict our ability to borrow under or expand our secured credit facility. As of September 30, 2006, we estimate that secured commercial bank indebtedness of approximately $5.4 billion could have been incurred under the most restrictive indenture covenant.

In September 2006, our wholly owned subsidiary, Nomac Drilling Corporation, sold 18 of its drilling rigs and related equipment for $187.5 million and entered into a master lease agreement under which it agreed to lease the rigs from the buyer for an initial term of eight years from October 1, 2006 at rental payments of $26.0 million annually. Nomac s lease obligations are guaranteed by Chesapeake and its other material domestic subsidiaries. This transaction was recorded as a sale and operating leaseback, with an aggregate deferred gain of $14.8 million on the sale which will be amortized to service operations expense over the lease term. Under the rig lease, we have the option to purchase the rigs on September 30, 2013 or on the expiration of the lease term for a purchase price equal to the then fair market value of the rigs. Additionally, we have the option to renew the rig lease for a negotiated renewal term at a periodic rental equal to the fair market rental value of the rigs as determined at the time of renewal.

Commitments related to these lease payments are not recorded in the accompanying condensed consolidated balance sheets. As of September 30, 2006, minimum future rig lease payments were as follows (in thousands):

2006	$ 6,130
2007	25,993
2008	25,993
2009	25,993
2010	25,993
Thereafter	97,478
Total	$ 207,580

Results of Operations Three Months Ended September 30, 2006 vs. September 30, 2005

General. For the Current Quarter, Chesapeake had net income of $548.3 million, or $1.13 per diluted common share, on total revenues of $1.929 billion. This compares to net income of $177.0 million, or $0.43 per diluted common share, on total revenues of $1.083 billion during the Prior Quarter.

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Oil and Natural Gas Sales. During the Current Quarter, oil and natural gas sales were $1.493 billion compared to $720.9 million in the Prior Quarter. In the Current Quarter, Chesapeake produced 146.9 bcfe at a weighted average price of $8.54 per mcfe, compared to 120.4 bcfe produced in the Prior Quarter at a weighted average price of $6.85 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $238.5 million and ($104.0) million in the Current Quarter and Prior Quarter, respectively). In the Current Quarter, the increase in prices resulted in an increase in revenue of $247.9 million and increased production resulted in a $181.8 million increase, for a total increase in revenues of $429.7 million (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Quarter to the Current Quarter is due to the combination of drilling and acquisitions completed in 2005 and 2006.

For the Current Quarter, we realized an average price per barrel of oil of $60.62, compared to $53.30 in the Prior Quarter (weighted average prices for both quarters discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.39 and $6.64 in the Current Quarter and Prior Quarter, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $301.4 million, or $2.05 per mcfe, in the Current Quarter and a net decrease of $122.6 million, or $1.02 per mcfe, in the Prior Quarter.

The change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming the Current Quarter production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $13.4 million and $12.8 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $2.2 million and $2.1 million, respectively, without considering the effect of derivative activities.

The following table shows our production by region for the Current Quarter and the Prior Quarter:

	For the Three Months Ended September 30,			
	2006		2005	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	80,946	55%	74,910	62%
South Texas and Texas Gulf Coast	19,421	13	17,018	14
Appalachian Basin	11,750	8		
Barnett Shale	11,557	8	4,898	4
Ark-La-Tex	11,529	8	10,945	9
Permian Basin	11,072	8	11,843	10
Other	615		743	1
Total Production	146,890	100%	120,357	100%

Natural gas production represented approximately 91% of our total production volume on a natural gas equivalent basis in the Current Quarter, compared to 90% in the Prior Quarter.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $398.1 million in oil and natural gas marketing sales to third parties in the Current Quarter, with corresponding oil and natural gas marketing expenses of $384.5 million, for a net margin of $13.6 million. This compares to sales of $361.9 million, expenses of $353.5 million and a net margin of $8.4 million in the Prior Quarter. In the Current Quarter, Chesapeake realized an increase in oil and natural gas marketing sales volumes.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired in the Current Period. Chesapeake recognized $38.1 million in service operations revenue in the Current Quarter with corresponding service operations expense of $18.8 million, for a net margin of $19.3 million. During the Prior Quarter, service operations for third parties were insignificant.

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Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $124.0 million in the Current Quarter compared to $80.8 million in the Prior Quarter. On a unit-of-production basis, production expenses were $0.84 per mcfe in the Current Quarter compared to $0.67 per mcfe in the Prior Quarter. The increase in the Current Quarter was primarily due to higher third-party field service costs, energy costs, ad valorem tax increases and personnel costs. We expect that production expenses for the remainder of 2006 will range from $0.85 to $0.95 per mcfe produced.

Production Taxes. Production taxes were $40.6 million and $53.1 million in the Current Quarter and the Prior Quarter, respectively. On a unit-of-production basis, production taxes were $0.28 per mcfe in the Current Quarter compared to $0.44 per mcfe in the Prior Quarter. This decrease is the result of an increase in production tax exemptions realized in addition to a decrease in natural gas prices. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for the remainder of 2006 to range from $0.36 to $0.40 per mcfe produced based on NYMEX prices of $56.25 per barrel of oil and natural gas prices ranging from $6.40 to $7.20 per mcf.

General and Administrative Expenses. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and natural gas properties, were $37.4 million in the Current Quarter and $15.8 million in the Prior Quarter. General and administrative expenses were $0.25 and $0.13 per mcfe for the Current Quarter and Prior Quarter, respectively. The increase in the Current Quarter was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $8.5 million and $5.2 million for the Current Quarter and Prior Quarter, respectively. We anticipate that general and administrative expenses for the remainder of 2006 will be between $0.27 and $0.33 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.11 per mcfe).

Our stock-based compensation for employees and non-employee directors is principally in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors since July 2005. Stock-based compensation awards before 2004 (and before 2005 for non-employee directors) were in the form of stock options. Employee stock-based compensation awards vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

Until December 31, 2005, as permitted under Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, as amended, we accounted for our stock options under the recognition and measurement provisions of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Generally, we recognized no compensation cost on grants of employee and non-employee director stock options because the exercise price was equal to the market price of our common stock on the date of grant. Effective January 1, 2006, we implemented the fair value recognition provisions of SFAS 123(R), *Share-Based Payment,* using the modified-prospective transition method. Under this transition method, compensation cost in 2006 includes the portion vesting in the period for (1) all share-based payments granted prior to, but not vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123 and (2) all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). Results for prior periods have not been restated.

Stock-based compensation expense increased from $5.2 million in the Prior Quarter to $8.5 million in the Current Quarter. This increase is primarily due to additional restricted stock grants to employees during the past year.

The discussion of stock-based compensation in note 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock, as well as the effects of our adoption of SFAS 123(R).

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $49.0 million and $29.5 million of internal costs in the Current Quarter and the Prior Quarter, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $343.7 million and $231.1 million during the Current Quarter and the Prior Quarter, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.34 and $1.92 in the Current Quarter and in the Prior Quarter, respectively. The $0.42 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of the tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2006 to be between $2.35 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $27.0 million in the Current Quarter, compared to $12.9 million in the Prior Quarter. The increase in the Current Quarter was primarily the result of depreciation of assets acquired in 2005 and 2006. These assets include various gathering facilities and compression equipment, new buildings constructed at our corporate headquarters complex and at various field office locations, additional drilling rigs and oilfield trucks and new information technology equipment and software. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent drilling rigs are used to drill Chesapeake wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for the remainder of 2006 to be between $0.19 and $0.23 per mcfe produced.

Interest and Other Income. Interest and other income was $5.1 million in the Current Quarter compared to $2.4 million in the Prior Quarter. The Current Quarter income consisted of $1.8 million of interest income, $2.3 million related to earnings of equity investees, a $0.1 million gain on sale of assets and $0.9 million of miscellaneous income. The Prior Quarter income consisted of $0.4 million of interest income, ($0.1) million related to earnings of equity investees and $2.1 million of miscellaneous income.

Interest Expense. Interest expense increased to $74.1 million in the Current Quarter compared to $58.6 million in the Prior Quarter as follows:

	Three Months Ended September 30,	
	2006	**2005**
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 122.3	$ 77.6
Capitalized interest	(49.3)	(20.8)
Amortization of loan discount	2.0	1.4
Unrealized (gain) loss on interest rate derivatives	(2.5)	1.2
Realized (gain) loss on interest rate derivatives	1.6	(0.8)
Total interest expense	$ 74.1	$ 58.6
Average long-term borrowings	$ 6,525	$ 4,047

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities) and the debt s carrying value amount is adjusted

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by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears later in Item 3 Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in the Current Quarter compared to $0.48 per mcfe in the Prior Quarter. We expect interest expense for the remainder of 2006 to be between $0.58 and $0.62 per mcfe produced (before considering the effect of interest rate derivatives).

Loss on Repurchases or Exchanges of Chesapeake Debt. We repurchased or exchanged Chesapeake debt in the Prior Quarter and incurred losses in connection with the transactions. The following table shows the losses related to these transactions ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Three Months Ended September 30, 2005:	**Retired**	**Premium**	**Other(a)**	**Total**
8.125% Senior Notes due 2011	$ 7.6	$ 0.5	$ 0.1	$ 0.6
9.0% Senior Notes due 2012	1.1	0.1	0.0	0.1
	$ 8.7	$ 0.6	$ 0.1	$ 0.7

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with retired notes and transaction costs.

There were no repurchases or exchanges of Chesapeake debt in the Current Quarter.

Income Tax Expense. Chesapeake recorded income tax expense of $336.1 million in the Current Quarter, compared to income tax expense of $101.7 million in the Prior Quarter. Our effective income tax rate increased to 38% in the Current Quarter compared to 36.5% in the Prior Quarter. This increase included the impact that both state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas House Bill 3 was signed into law which eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. Although the new margin tax is not effective until 2007, the provisions of SFAS 109, *Accounting for Income Taxes*, require us to record the impact that this change has on our liability for additional deferred income taxes in the period of enactment. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Results of Operations Nine Months Ended September 30, 2006 vs. September 30, 2005

General. For the Current Period, Chesapeake had net income of $1.532 billion, or $3.40 per diluted common share, on total revenues of $5.458 billion. This compares to net income of $495.8 million, or $1.32 per diluted common share, on total revenues of $2.914 billion during the Prior Period.

Oil and Natural Gas Sales. During the Current Period, oil and natural gas sales were $4.190 billion compared to $2.032 billion in the Prior Period. In the Current Period, Chesapeake produced 426.3 bcfe at a weighted average price of $8.77 per mcfe, compared to 338.2 bcfe produced in the Prior Period at a weighted average price of $6.42 per mcfe (weighted average prices exclude the effect of unrealized gains or (losses) on oil and natural gas derivatives of $452.6 million and ($137.1) million in the Current Period and Prior Period, respectively). In the Current Period, the increase in prices resulted in an increase in revenue of $1.003 billion and increased production resulted in a $565.5 million increase, for a total increase in revenues of $1.568 billion (excluding unrealized gains or losses on oil and natural gas derivatives). The increase in production from the Prior Period to the Current Period is due to the combination of drilling as well as acquisitions completed in 2005 and the Current Period.

For the Current Period, we realized an average price per barrel of oil of $58.86 compared to $46.04 in the Prior Period (weighted average prices for both periods discussed exclude the effect of unrealized gains or losses on derivatives). Natural gas prices realized per mcf (excluding unrealized gains or losses on derivatives) were $8.66 and $6.27 in the Current Period and Prior Period, respectively. Realized gains or losses from our oil and natural gas derivatives resulted in a net increase in oil and natural gas revenues of $807.1 million, or $1.89 per mcfe, in the Current Period and a net decrease of $126.6 million, or $0.37 per mcfe, in the Prior Period.

The change in oil and natural gas prices has a significant impact on our oil and natural gas revenues and cash flows. Assuming the Current Period production levels, a change of $0.10 per mcf of natural gas sold would have resulted in an increase or decrease in revenues and cash flow of approximately $38.8 million and $36.9 million, respectively, and a change of $1.00 per barrel of oil sold would have resulted in an increase or decrease in revenues and cash flow of approximately $6.4 million and $6.1 million, respectively, without considering the effect of derivative activities.

The following table shows our production by region for the Current Period and the Prior Period:

	For the Nine Months Ended September 30,			
	2006		2005	
	Mmcfe	Percent	Mmcfe	Percent
Mid-Continent	233,078	55%	222,290	65%
South Texas and Texas Gulf Coast	59,040	14	45,082	13
Permian Basin	34,582	8	28,955	9
Ark-La-Tex	34,410	8	28,845	9
Appalachian Basin	33,268	8		
Barnett Shale	30,035	7	10,927	3
Other	1,905		2,065	1
Total Production	426,318	100%	338,164	100%

Natural gas production represented approximately 91% of our total production volume on a natural gas equivalent basis in the Current Period, compared to 90% in the Prior Period.

Oil and Natural Gas Marketing Sales and Operating Expenses. Oil and natural gas marketing activities are substantially for third parties that are owners in Chesapeake-operated wells. Chesapeake recognized $1.170 billion in oil and natural gas marketing sales to third parties in the Current Period, with corresponding oil and natural gas marketing expenses of $1.132 billion, for a net margin of $38.6 million. This compares to sales of $882.0 million, expenses of $860.8 million and a net margin of $21.2 million in the Prior Period. In the Current Period, Chesapeake realized an increase in oil and natural gas marketing sales volumes and an increase in oil and natural gas prices.

Service Operations Revenue and Operating Expenses. Service operations consist of third-party revenue and operating expenses related to our drilling and oilfield trucking operations. These operations have grown as a result of businesses we acquired in the Current Period. Chesapeake recognized $97.5 million in service operations revenue in the Current Period with corresponding service operations expenses of $48.9 million, for a net margin of $48.6 million principally associated with businesses acquired in the Current Period. During the Prior Period, service operations for third parties were insignificant.

Production Expenses. Production expenses, which include lifting costs and ad valorem taxes, were $364.1 million in the Current Period compared to $222.7 million in the Prior Period. On a unit-of-production basis, production expenses were $0.85 per mcfe in the Current Period compared to $0.66 per mcfe in the Prior Period. The increase in the Current Period was primarily due to higher third-party field service costs, energy costs, ad valorem tax increases and personnel costs. We expect that production expenses for the remainder of 2006 will range from $0.85 to $0.95 per mcfe produced.

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Production Taxes. Production taxes were $129.9 million and $136.3 million in the Current Period and the Prior Period, respectively. On a unit-of-production basis, production taxes were $0.30 per mcfe in the Current

Period compared to $0.40 per mcfe in the Prior Period. The Current Period included a $2.1 million accrual for certain severance tax claims and then a subsequent reversal of the cumulative $11.6 million accrual for such severance tax claims as a result of their dismissal. The Prior Period included an accrual of $5.0 million associated with such severance tax claims. Excluding these items, production taxes were $0.33 per mcfe in the Current Period and $0.39 per mcfe in the Prior Period. This decrease is the result of an increase in production tax exemptions realized. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil and natural gas prices are higher. We expect production taxes for the remainder of 2006 to range from $0.36 to $0.40 per mcfe produced based on NYMEX prices of $56.25 per barrel of oil and natural gas prices ranging from $6.40 to $7.20 per mcf.

General and Administrative Expenses. General and administrative expenses, which are net of internal payroll and non-payroll costs capitalized in our oil and natural gas properties, were $99.7 million in the Current Period and $39.6 million in the Prior Period. General and administrative expenses were $0.23 and $0.12 per mcfe for the Current Period and Prior Period, respectively. The increase in the Current Period was the result of the company s overall growth as well as cost and wage inflation. Included in general and administrative expenses is stock-based compensation of $21.3 million and $10.2 million for the Current Period and Prior Period, respectively. We anticipate that general and administrative expenses for the remainder of 2006 will be between $0.27 and $0.33 per mcfe produced (including stock-based compensation ranging from $0.10 to $0.11 per mcfe).

Our stock-based compensation for employees and non-employee directors is principally in the form of restricted stock. We have awarded shares of restricted stock to employees since January 2004 and to non-employee directors annually since July 2005. Employee compensation awards before 2004 (and before 2005 for non-employee directors) were in the form of stock options. These stock-based compensation awards vest over a period of four or five years. Our non-employee director awards vest over a period of three years.

Until December 31, 2005, as permitted under Statement of Financial Accounting Standards (SFAS) No. 123, *Accounting for Stock-Based Compensation*, as amended, we accounted for our stock options under the recognition and measurement provisions of APB Opinion No. 25, *Accounting for Stock Issued to Employees*, and related interpretations. Generally, we recognized no compensation cost on grants of employee and non-employee director stock options because the exercise price was equal to the market price of our common stock on the date of grant. Effective January 1, 2006, we implemented the fair value recognition provisions of SFAS 123(R), *Share-Based Payment,* using the modified-prospective transition method. Under this transition method, compensation cost in 2006 includes the portion vesting in the period for (1) all share-based payments granted prior to, but not vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS 123 and (2) all share-based payments granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS 123(R). Results for prior periods have not been restated.

Stock-based compensation expense increased from $10.2 million in the Prior Period to $21.3 million in the Current Period. Of this increase, $1.9 million was due to stock option expense, $9.1 million was due to a higher number of unvested restricted shares outstanding during the Current Period compared to the Prior Period and $0.1 million was due to stock granted to a new director.

The discussion of stock-based compensation in note 1 to the financial statements included in Part I of this report provides additional detail on the accounting for and reporting of our stock options and restricted stock, as well as the effects of our adoption of SFAS 123(R).

Chesapeake follows the full-cost method of accounting under which all costs associated with property acquisition, exploration and development activities are capitalized. We capitalize internal costs that can be directly identified with our exploration and development activities and do not include any costs related to production, general corporate overhead or similar activities. We capitalized $119.3 million and $75.3 million of internal costs in the Current Period and the Prior Period, respectively, directly related to our oil and natural gas property acquisition, exploration and development efforts.

Oil and Natural Gas Depreciation, Depletion and Amortization. Depreciation, depletion and amortization of oil and natural gas properties was $976.8 million and $621.5 million during the Current Period and the Prior Period, respectively. The average DD&A rate per mcfe, which is a function of capitalized costs, future development costs and the related underlying reserves in the periods presented, was $2.29 and $1.84 in the Current Period and in the Prior Period, respectively. The $0.45 increase in the average DD&A rate is primarily the result of higher drilling costs and higher costs associated with acquisitions, including the recognition of the tax effect of acquisition costs in excess of tax basis acquired in certain corporate acquisitions. We expect the DD&A rate for the remainder of 2006 to be between $2.35 and $2.40 per mcfe produced.

Depreciation and Amortization of Other Assets. Depreciation and amortization of other assets was $74.1 million in the Current Period, compared to $34.8 million in the Prior Period. The increase in the Current Period was primarily the result of the depreciation of recently acquired assets resulting from our acquisition of various gathering facilities and compression equipment, the construction of new buildings at our corporate headquarters complex and at various field office locations, the purchase of additional drilling rigs and oilfield trucks and the purchase of additional information technology equipment and software. Property and equipment costs are depreciated on a straight-line basis. Buildings are depreciated over 15 to 39 years, gathering facilities are depreciated over seven to 20 years, drilling rigs are depreciated over 15 years and all other property and equipment are depreciated over the estimated useful lives of the assets, which range from two to seven years. To the extent drilling rigs are used to drill our wells, a substantial portion of the depreciation is capitalized in oil and natural gas properties as exploration or development costs. We expect depreciation and amortization of other assets for the remainder of 2006 to be between $0.19 and $0.23 per mcfe produced.

Employee Retirement Expense. Our President and Chief Operating Officer, Tom L. Ward, resigned as a director, officer and employee of the company effective February 10, 2006. Mr. Ward s Resignation Agreement provided for the immediate vesting of all of his unvested stock options and restricted stock on February 10, 2006. As a result of such vesting, options to purchase 724,615 shares of Chesapeake s common stock at an average exercise price of $8.01 per share and 1,291,875 shares of restricted common stock became immediately vested. As a result, we incurred an expense of $54.8 million in the Current Period.

Interest and Other Income. Interest and other income was $19.7 million in the Current Period compared to $7.8 million in the Prior Period. The Current Period income consisted of $3.1 million of interest income, $9.5 million related to earnings of equity investees, a $3.5 million gain on sale of assets and $3.6 million of miscellaneous income. The Prior Period income consisted of $3.5 million of interest income, $1.1 million related to earnings of equity investees and $3.2 million of miscellaneous income.

Interest Expense. Interest expense increased to $220.2 million in the Current Period compared to $155.6 million in the Prior Period as follows:

	Nine Months Ended September 30, 2006	Nine Months Ended September 30, 2005
	($ in millions)	
Interest expense on senior notes and revolving bank credit facility	$ 335.8	$ 210.7
Capitalized interest	(119.2)	(54.8)
Amortization of loan discount	5.3	4.2
Unrealized (gain) loss on interest rate derivatives	(0.8)	(1.9)
Realized (gain) loss on interest rate derivatives	(0.9)	(2.6)
Total interest expense	$ 220.2	$ 155.6
Average long-term borrowings	$ 6,125	$ 3,593

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We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Any resulting differences are recorded currently as ineffectiveness in the consolidated statements of operations as an adjustment to interest expense. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense. A detailed explanation of our interest rate derivative activity appears later in Item 3 Quantitative and Qualitative Disclosures About Market Risk.

Interest expense, excluding unrealized gains or losses on derivatives and net of amounts capitalized, was $0.52 per mcfe in the Current Period compared to $0.47 per mcfe in the Prior Period. We expect interest expense for the remainder of 2006 to be between $0.58 and $0.62 per mcfe produced (before considering the effect of interest rate derivatives).

Gain on Sale of Investment. In the Current Period, Chesapeake sold its investment in publicly-traded Pioneer Drilling Company (Pioneer) common stock, realizing proceeds of $158.9 million and a gain of $117.4 million. We owned 17% of the common stock of Pioneer, which we began acquiring in 2003.

Loss on Repurchases or Exchanges of Chesapeake Senior Notes. We repurchased or exchanged Chesapeake debt in the Prior Period and incurred losses in connection with the transactions. The following table shows the losses related to these transactions ($ in millions):

	Notes	Loss on Repurchases/Exchanges		
For the Nine Months Ended September 30, 2005:	**Retired**	**Premium**	**Other(a)**	**Total**
8.375% Senior Notes due 2008	$ 11.0	$ 0.8	$ 0.1	$ 0.9
8.125% Senior Notes due 2011	245.4	17.3	4.4	21.7
9.0% Senior Notes due 2012	300.0	41.4	6.0	47.4
	$ 556.4	$ 59.5	$ 10.5	$ 70.0

(a) Includes write-offs of discounts, deferred charges and interest rate derivatives associated with retired notes and transaction costs.

There were no repurchases or exchanges of Chesapeake debt in the Current Period.

Income Tax Expense. Chesapeake recorded income tax expense of $963.1 million in the Current Period, compared to income tax expense of $285.0 million in the Prior Period. Our effective income tax rate increased to 38.6% in the Current Period compared to 36.5% in the Prior Period. This increase included the impact that both state income taxes and permanent differences had on our overall effective rate along with the effect of a Texas tax law change. In May 2006, Texas House Bill 3 was signed into law which eliminated the existing franchise tax and replaced it with a new income-based margin tax. The new tax is effective for tax returns due on or after January 1, 2008 for our 2007 business activity. Although the new margin tax is not effective until 2007, the provisions of SFAS 109, *Accounting for Income Taxes*, require us to record the impact that this change has on our liability for deferred income taxes in the period of enactment. As a result, we recorded $15 million in additional deferred state income tax expense, net of the federal income tax benefit, in the Current Period. Excluding the effect of this adjustment, our effective income tax rate was 38% for the Current Period. All 2005 income tax expense was deferred, and we expect most, if not all, of our 2006 income tax expense to be deferred.

Critical Accounting Policies

We consider accounting policies related to hedging, oil and natural gas properties, income taxes and business combinations to be critical policies. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our annual report on Form 10-K for the year ended December 31, 2005.

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Recently Issued Accounting Standards

The Financial Accounting Standards Board (FASB) recently issued the following standards which were reviewed by Chesapeake to determine the potential impact on our financial statements upon adoption.

In December 2004, the FASB issued SFAS 123(R), *Share-Based Payment*, a revision of SFAS 123, accounting for stock-based compensation. This statement establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services by requiring a public entity to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. We adopted this statement effective January 1, 2006. The effect of SFAS 123(R) is more fully described in Note 1.

In September 2005, the Emerging Issues Task Force (EITF) reached a consensus on Issue No. 04-13, *Accounting for Purchases and Sales of Inventory with the Same Counterparty*. EITF Issue No. 04-13 requires that purchases and sales of inventory with the same counterparty in the same line of business should be accounted for as a single non-monetary exchange, if entered into in contemplation of one another. The consensus is effective for inventory arrangements entered into, modified or renewed in interim or annual reporting periods beginning after March 15, 2006. We adopted this issue effective April 1, 2006. The adoption of EITF Issue No. 04-13 did not have a material impact on our financial statements.

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. FIN 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS 109, *Accounting for Income Taxes*. FIN 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding de-recognition, classification and disclosure of these uncertain tax positions. FIN 48 is effective for fiscal years beginning after December 15, 2006. We do not expect that FIN 48 will have a material impact on our financial position, results of operations or cash flows.

In February 2006, the FASB issued SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments an amendment of FASB Statements No. 133 and 140*. SFAS 155 permits an entity to measure at fair value any financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity s first fiscal year that begins after September 15, 2006. We are currently evaluating the provisions of SFAS 155 and believe that adoption will not have a material effect on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. This statement defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles (GAAP), and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We are currently assessing the impact SFAS 157 will have on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans*. This statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. This statement is effective as of the end of the fiscal year ending after December 15, 2006. We do not expect that SFAS 158 will have a material impact on our financial position, results of operations or cash flows.

Forward-Looking Statements

This report includes 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. Forward-looking statements give our current expectations or forecasts of future events. They include statements regarding oil and natural gas reserve

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estimates, planned capital expenditures, the drilling of oil and natural gas wells and future acquisitions, expected oil and natural gas production, cash flow and anticipated liquidity, business strategy and other plans and objectives for future operations and expected future expenses. Statements concerning the fair values of derivative contracts and their estimated contribution to our future results of operations are based upon market information as of a specific date. These market prices are subject to significant volatility.

Although we believe the expectations and forecasts reflected in these and other forward-looking statements are reasonable, we can give no assurance they will prove to have been correct. They can be affected by inaccurate assumptions or by known or unknown risks and uncertainties. Factors that could cause actual results to differ materially from expected results are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005 and include:

- the volatility of oil and natural gas prices,
- our level of indebtedness,
- the strength and financial resources of our competitors,
- the availability of capital on an economic basis to fund reserve replacement costs,
- our ability to replace reserves and sustain production,
- uncertainties inherent in estimating quantities of oil and natural gas reserves and projecting future rates of production and the timing of development expenditures,
- uncertainties in evaluating oil and natural gas reserves of acquired properties and associated potential liabilities,
- inability to effectively integrate and operate acquired companies and properties,
- unsuccessful exploration and development drilling,
- declines in the value of our oil and natural gas properties resulting in ceiling test write-downs,
- lower prices realized on oil and natural gas sales and collateral required to secure hedging liabilities resulting from our commodity price risk management activities,
- lower oil and natural gas prices negatively affecting our ability to borrow, and
- drilling and operating risks.

We caution you not to place undue reliance on these forward-looking statements, which speak only as of the date of this report, and we undertake no obligation to update this information. We urge you to carefully review and consider the disclosures made in this report and our other filings with the Securities and Exchange Commission that attempt to advise interested parties of the risks and factors that may affect our business.

ITEM 3. *Quantitative and Qualitative Disclosures About Market Risk*

Oil and Natural Gas Hedging Activities

Our results of operations and operating cash flows are impacted by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of September 30, 2006, our oil and natural gas derivative instruments were comprised of swaps, cap-swaps, basis protection swaps, call options and collars. These instruments allow us to predict with greater certainty the effective oil and natural gas prices to be received for our hedged production. Although derivatives often fail to achieve 100% effectiveness for accounting purposes, we believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

For swap instruments, Chesapeake receives a fixed price for the hedged commodity and pays a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

For cap-swaps, Chesapeake receives a fixed price and pays a floating market price. The fixed price received by Chesapeake includes a premium in exchange for a cap limiting the counterparty s exposure. In other words, there is no limit to Chesapeake s exposure but there is a limit to the downside exposure of the counterparty.

Basis protection swaps are arrangements that guarantee a price differential for oil or natural gas from a specified delivery point. For Mid-Continent basis protection swaps, which have negative differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract. For Appalachian Basin basis protection swaps, which have positive differentials to NYMEX, Chesapeake receives a payment from the counterparty if the price differential is less than the stated terms of the contract and pays the counterparty if the price differential is greater than the stated terms of the contract.

For call options, Chesapeake receives a cash premium from the counterparty in exchange for the sale of a call option. If the market price exceeds the fixed price of the call option, Chesapeake pays the counterparty such excess. If the market price settles below the fixed price of the call option, no payment is due from Chesapeake.

Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the put strike price, Chesapeake receives the fixed price and pays the market price. If the market price is between the call and the put strike price, no payments are due from either party.

Chesapeake enters into counter-swaps from time to time for the purpose of locking-in the value of a swap. Under the counter-swap, Chesapeake receives a floating price for the hedged commodity and pays a fixed price to the counterparty. The counter-swap is 100% effective in locking-in the value of a swap since subsequent changes in the market value of the swap are entirely offset by subsequent changes in the market value of the counter-swap. We refer to this locked-in value as a locked swap. Generally, at the time Chesapeake enters into a counter-swap, Chesapeake removes the original swap s designation as a cash flow hedge and classifies the original swap as a non-qualifying hedge under SFAS 133. The reason for this new designation is that collectively the swap and the counter-swap no longer hedge the exposure to variability in expected future cash flows. Instead, the swap and counter-swap effectively lock-in a specific gain (or loss) that will be unaffected by subsequent variability in oil and natural gas prices. Any locked-in gain or loss is recorded in accumulated other comprehensive income and reclassified to oil and natural gas sales in the month of related production.

With respect to counter-swaps that are designed to lock-in the value of cap-swaps, the counter-swap is effective in locking-in the value of the cap-swap until the floating price reaches the cap (or floor) stipulated in the cap-swap agreement. The value of the counter-swap will increase (or decrease), but in the opposite direction, as the value of the cap-swap decreases (or increases) until the floating price reaches the pre-determined cap (or floor) stipulated in the cap-swap agreement. However, because of the written put option embedded in the cap-swap, the changes in value of the cap-swap are not completely effective in offsetting changes in value of the corresponding counter-swap. Changes in the value of cap-swaps and counter-swaps are recorded as adjustments to oil and natural gas sales.

In accordance with FASB Interpretation No. 39, to the extent that a legal right of setoff exists, Chesapeake nets the value of its derivative arrangements with the same counterparty in the accompanying condensed consolidated balance sheets.

Chesapeake enters into basis protection swaps for the purpose of locking-in a price differential for oil or natural gas from a specified delivery point. We currently have basis protection swaps covering six different delivery points, four in the Mid-Continent and two in the Appalachian Basin, which correspond to the actual prices we receive for much of our natural gas production. By entering into these basis protection swaps, we have

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effectively reduced our exposure to market changes in future natural gas price differentials. As of September 30, 2006, the fair value of our basis protection swaps was $178.8 million. As of September 30, 2006, our Mid-Continent basis protection swaps covered approximately 29% of our anticipated Mid-Continent natural gas production remaining in 2006, 25% in 2007, 18% in 2008 and 13% in 2009. As of September 30, 2006, our Appalachian Basin basis protection swaps cover approximately 74% of our anticipated Appalachian Basin natural gas production in 2007, 65% in 2008 and 30% in 2009.

Gains or losses from derivative transactions are reflected as adjustments to oil and natural gas sales on the condensed consolidated statements of operations. Realized gains (losses) included in oil and natural gas sales were $301.4 million, ($122.6) million, $807.1 million and ($126.6) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within oil and natural gas sales. Unrealized gains (losses) included in oil and natural gas sales were $238.5 million, ($104.0) million, $452.6 million and ($137.1) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

Following provisions of SFAS 133, changes in the fair value of derivative instruments designated as cash flow hedges, to the extent they are effective in offsetting cash flows attributable to the hedged risk, are recorded in other comprehensive income until the hedged item is recognized in earnings. Any change in fair value resulting from ineffectiveness is recognized currently in oil and natural gas sales as unrealized gains (losses). We recorded an unrealized gain (loss) on ineffectiveness of $171.8 million, ($99.5) million, $336.7 million and ($98.9) million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

As of September 30, 2006, we had the following open oil and natural gas derivative instruments (excluding CNR derivatives assumed) designed to hedge a portion of our oil and natural gas production for periods after September 2006:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received ($ in thousands)	Fair Value at September 30, 2006 ($ in thousands)
Natural Gas (mmbtu):								
Swaps:								
4Q 2006	106,585,000	$ 9.68	$	$	$	Yes	$	$ 422,505
1Q 2007	102,150,000	11.09				Yes		336,329
2Q 2007	78,715,000	9.18				Yes		152,602
3Q 2007	79,580,000	9.24				Yes		142,030
4Q 2007	79,580,000	9.90				Yes		135,751
1Q 2008	64,610,000	10.84				Yes		114,992
2Q 2008	64,610,000	8.45				Yes		71,924
3Q 2008	65,320,000	8.51				Yes		67,639
4Q 2008	65,320,000	9.15				Yes		68,693
1Q 2009	900,000	10.53				Yes		1,551
2Q 2009	910,000	8.29				Yes		1,093
3Q 2009	920,000	8.34				Yes		1,026
4Q 2009	920,000	8.95				Yes		998
Basis Protection Swaps (Mid-Continent):								
4Q 2006	33,720,000				(0.32)	No		13,446
1Q 2007	32,850,000				(0.29)	No		18,781
2Q 2007	34,125,000				(0.35)	No		13,449
3Q 2007	34,500,000				(0.35)	No		11,385
4Q 2007	35,720,000				(0.32)	No		25,796
1Q 2008	33,215,000				(0.30)	No		28,210
2Q 2008	26,845,000				(0.25)	No		15,241
3Q 2008	27,140,000				(0.25)	No		13,469
4Q 2008	31,410,000				(0.28)	No		18,293
1Q 2009	26,100,000				(0.32)	No		13,746

2Q 2009	20,020,000	(0.28)	No	1,906
3Q 2009	20,240,000	(0.28)	No	1,348
4Q 2009	20,240,000	(0.28)	No	4,726

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	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received ($ in thousands)	Fair Value at September 30, 2006 ($ in thousands)
Basis Protection Swaps (Appalachian Basin):								
1Q 2007	9,000,000	$	$	$	$ 0.35	No	$	$ 273
2Q 2007	9,100,000				0.35	No		(462)
3Q 2007	9,200,000				0.35	No		(491)
4Q 2007	9,200,000				0.35	No		(55)
1Q 2008	9,100,000				0.35	No		652
2Q 2008	9,100,000				0.35	No		(338)
3Q 2008	9,200,000				0.35	No		(365)
4Q 2008	9,200,000				0.35	No		(152)
1Q 2009	4,500,000				0.31	No		205
2Q 2009	4,550,000				0.31	No		(108)
3Q 2009	4,600,000				0.31	No		(121)
4Q 2009	4,600,000				0.31	No		(2)
Cap-Swaps:								
4Q 2006	11,960,000	6.89	5.13			No		(1,869)
1Q 2007	14,400,000	11.44	5.73			No		28,620
2Q 2007	19,110,000	9.57	5.91			No		8,120
3Q 2007	19,320,000	9.76	5.91			No		2,402
4Q 2007	19,320,000	10.56	5.91			No		6,113
1Q 2008	19,110,000	11.58	6.18			No		11,135
2Q 2008	19,110,000	10.00	6.18			No		6,369
3Q 2008	19,320,000	10.09	6.18			No		3,863
4Q 2008	19,320,000	10.65	6.18			No		4,383
Counter Swaps:								
4Q 2006	(36,605,000)	5.27				No		600
1Q 2007	(900,000)	7.53				No		243
2Q 2007	(4,550,000)	7.09				No		675
3Q 2007	(4,600,000)	7.31				No		659
4Q 2007	(4,600,000)	8.03				No		755
1Q 2008	(4,550,000)	8.84				No		1,000
2Q 2008	(4,550,000)	7.14				No		880
3Q 2008	(4,600,000)	7.28				No		903
4Q 2008	(4,600,000)	7.90				No		931
Call Options:								
4Q 2006	1,840,000			12.50		No	1,932	(51)
1Q 2007	6,300,000			11.58		No	1,890	(2,575)
2Q 2007	6,370,000			9.96		No	1,911	(3,077)
3Q 2007	6,440,000			10.04		No	1,932	(4,835)
4Q 2007	6,440,000			10.56		No	1,932	(6,590)
1Q 2008	1,820,000			12.50		No	1,911	(1,997)
2Q 2008	1,820,000			12.50		No	1,911	(545)
3Q 2008	1,840,000			12.50		No	1,932	(773)
4Q 2008	1,840,000			12.50		No	1,932	(1,373)
Locked Swaps:								
4Q 2006	6,440,000					No		(4,706)
1Q 2007	6,300,000					No		(4,789)
2Q 2007	6,370,000					No		(2,517)
3Q 2007	6,440,000					No		(2,049)
4Q 2007	6,440,000					No		(2,272)
Total Natural Gas							17,283	1,733,598

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	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	Weighted Average Differential	SFAS 133 Hedge	Net Premiums Received ($ in thousands)	Fair Value at September 30, 2006 ($ in thousands)
Oil (bbls):								
Swaps:								
4Q 2006	1,656,000	$ 65.38	$	$	$	Yes	$	$ 2,275
1Q 2007	1,350,000	67.98				Yes		2,356
2Q 2007	1,092,000	70.04				Yes		2,747
3Q 2007	1,104,000	69.71				Yes		1,556
4Q 2007	1,104,000	69.31				Yes		697
1Q 2008	1,001,000	70.44				Yes		1,491
2Q 2008	1,001,000	70.02				Yes		1,161
3Q 2008	1,012,000	69.60				Yes		968
4Q 2008	920,000	68.79				Yes		476
1Q 2009	45,000	66.64				Yes		(50)
2Q 2009	45,500	66.27				Yes		(47)
3Q 2009	46,000	65.92				Yes		(43)
4Q 2009	46,000	65.56				Yes		(40)
Cap-Swaps:								
4Q 2006	184,000	68.02	50.00			No		633
1Q 2007	360,000	78.53	56.25			No		3,805
2Q 2007	364,000	78.53	56.25			No		3,161
3Q 2007	368,000	78.53	56.25			No		2,736
4Q 2007	368,000	78.53	56.25			No		2,444
1Q 2008	273,000	77.60	55.00			No		1,487
2Q 2008	273,000	77.60	55.00			No		1,396
3Q 2008	276,000	77.60	55.00			No		1,348
4Q 2008	276,000	77.60	55.00			No		1,307
Total Oil								31,864
Total Natural Gas and Oil							$ 17,283	$ 1,765,462

We have established the fair value of all derivative instruments using estimates of fair value reported by our counterparties and subsequently evaluated internally using established index prices and other sources. The actual contribution to our future results of operations will be based on the market prices at the time of settlement and may be more or less than the fair value estimates used at September 30, 2006.

Based upon the market prices at September 30, 2006, we expect to transfer approximately $530.2 million (net of income taxes) of the gain included in the balance in accumulated other comprehensive income to earnings during the next 12 months in the related month of production. All transactions hedged as of September 30, 2006 are expected to mature by December 31, 2009.

Additional information concerning the fair value of our oil and natural gas derivative instruments, including CNR derivatives assumed, is as follows:

	2006 ($ in thousands)
Fair value of contracts outstanding, as of January 1	$ (945,814)
Change in fair value of contracts during the period	3,261,182
Fair value of contracts when entered into during the period	(32,300)
Contracts realized or otherwise settled during the period	(807,074)
Fair value of contracts outstanding, as of September 30	$ 1,475,994

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The change in the fair value of our derivative instruments since January 1, 2006 resulted from the settlement of derivatives for a realized gain, as well as a decrease in natural gas prices. Derivative instruments reflected as current in the condensed consolidated balance sheet represent the estimated fair value of derivative instrument settlements scheduled to occur over the subsequent twelve-month period based on market prices for oil and natural gas as of the condensed consolidated balance sheet date. The derivative settlement amounts are not due and payable until the month in which the related underlying hedged transaction occurs.

We assumed certain liabilities related to open derivative positions in connection with our acquisition of Columbia Natural Resources, LLC in November 2005. In accordance with SFAS 141, these derivative positions were recorded at fair value in the purchase price allocation as a liability of $592 million. The recognition of the derivative liability and other assumed liabilities resulted in an increase in the total purchase price which was allocated to the assets acquired. Because of this accounting treatment, only cash settlements for changes in fair value subsequent to the acquisition date for the derivative positions assumed result in adjustments to our oil and natural gas revenues upon settlement. For example, if the fair value of the derivative positions assumed do not change then upon the sale of the underlying production and corresponding settlement of the derivative positions, cash would be paid to the counterparties and there would be no adjustment to oil and natural gas revenues related to the derivative positions. If, however, the actual sales price is different from the price assumed in the original fair value calculation, the difference would be reflected as either a decrease or increase in oil and natural gas revenues, depending upon whether the sales price was higher or lower, respectively, than the prices assumed in the original fair value calculation. For accounting purposes, the net effect of these acquired hedges is that we hedged the production volumes at market prices on the date of our acquisition of CNR.

Pursuant to Statement of Financial Accounting Standards No. 149, *Amendment of SFAS 133 on Derivative Instruments and Hedging Activities*, the derivative instruments assumed in connection with the CNR acquisition are deemed to contain a significant financing element and all cash flows associated with these positions are reported as financing activity in the statement of cash flows for the periods in which settlement occurs.

The following details the assumed CNR derivatives remaining as of September 30, 2006:

	Volume	Weighted Average Fixed Price to be Received (Paid)	Weighted Average Put Fixed Price	Weighted Average Call Fixed Price	SFAS 133 Hedge	Fair Value at September 30, 2006 ($ in thousands)
Natural Gas (mmbtu):						
Swaps:						
4Q 2006	10,626,000	$ 4.86	$	$	Yes	$ (9,313)
1Q 2007	10,350,000	4.82			Yes	(30,297)
2Q 2007	10,465,000	4.82			Yes	(24,548)
3Q 2007	10,580,000	4.82			Yes	(26,672)
4Q 2007	10,580,000	4.82			Yes	(33,722)
1Q 2008	9,555,000	4.68			Yes	(39,074)
2Q 2008	9,555,000	4.68			Yes	(23,387)
3Q 2008	9,660,000	4.68			Yes	(24,581)
4Q 2008	9,660,000	4.66			Yes	(29,997)
1Q 2009	4,500,000	5.18			Yes	(14,498)
2Q 2009	4,550,000	5.18			Yes	(7,627)
3Q 2009	4,600,000	5.18			Yes	(8,162)
4Q 2009	4,600,000	5.18			Yes	(10,574)
Collars:						
1Q 2009	900,000		4.50	6.00	Yes	(2,538)
2Q 2009	910,000		4.50	6.00	Yes	(1,268)
3Q 2009	920,000		4.50	6.00	Yes	(1,375)
4Q 2009	920,000		4.50	6.00	Yes	(1,835)
Total Natural Gas						$ (289,468)

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Subsequent to September 30, 2006, Chesapeake lifted a portion of its fourth quarter 2006 and full-year 2007, 2008 and 2009 hedges and as a result received $407 million in cash from its hedging counterparties. The gain will be recorded in accumulated other comprehensive income and in unrealized oil and natural gas sales based on the designation of the hedges. The gain will be recognized in realized oil and natural gas sales in the month of the hedged production.

Interest Rate Risk

The table below presents principal cash flows and related weighted average interest rates by expected maturity dates. As of September 30, 2006, the fair value of the fixed-rate long-term debt has been estimated based on quoted market prices.

	Years of Maturity							
	2006	2007	2008	2009	2010	Thereafter	Total	Fair Value
	($ in billions)							
Liabilities:								
Long-term debt fixed-rate (a)	$	$	$	$	$	$ 6.525	$ 6.525	$ 6.317
Average interest rate						6.4%	6.4%	6.4%
Long-term debt variable rate	$	$	$	$	$	$ 1.464	$ 1.464	$ 1.464
Average interest rate						6.5%	6.5%	6.5%

(a) This amount does not include the discount included in long-term debt of ($103.9) million and the discount for interest rate swaps of ($23.6) million.

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and short-term investments and the interest rate we pay on borrowings under our revolving bank credit facility. All of our other long-term indebtedness is fixed rate and, therefore, does not expose us to the risk of earnings or cash flow loss due to changes in market interest rates. However, changes in interest rates do affect the fair value of our debt.

Interest Rate Derivatives

We use interest rate derivatives to mitigate our exposure to the volatility in interest rates. For interest rate derivative instruments designated as fair value hedges (in accordance with SFAS 133), changes in fair value are recorded on the condensed consolidated balance sheets as assets (liabilities), and the debt s carrying value amount is adjusted by the change in the fair value of the debt subsequent to the initiation of the derivative. Changes in the fair value of derivative instruments not qualifying as fair value hedges are recorded currently as adjustments to interest expense.

Gains or losses from certain derivative transactions are reflected as adjustments to interest expense on the condensed consolidated statements of operations. Realized gains (losses) included in interest expense were ($1.6) million, $0.8 million, $0.9 million and $2.6 million in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively. Pursuant to SFAS 133, certain derivatives do not qualify for designation as fair value hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in the condensed consolidated statements of operations as unrealized gains (losses) within interest expense. Unrealized gains (losses) included in interest expense were $2.5 million, ($1.2) million, $0.8 million and $1.9 million, in the Current Quarter, Prior Quarter, Current Period and Prior Period, respectively.

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As of September 30, 2006, the following interest rate swaps used to convert a portion of our long-term fixed-rate debt to floating-rate debt were outstanding:

Term	Notional Amount	Fixed Rate	Floating Rate	Fair Value ($ in thousands)
September 2004 August 2012	$ 75,000,000	9.000%	6 month LIBOR plus 452 basis points	$ (2,919)
July 2005 January 2015	$ 150,000,000	7.750%	6 month LIBOR plus 289 basis points	(6,301)
July 2005 June 2014	$ 150,000,000	7.500%	6 month LIBOR plus 282 basis points	(6,456)
September 2005 August 2014	$ 250,000,000	7.000%	6 month LIBOR plus 205.5 basis points	(7,305)
October 2005 June 2015	$ 200,000,000	6.375%	6 month LIBOR plus 112 basis points	(3,308)
October 2005 January 2018	$ 250,000,000	6.250%	6 month LIBOR plus 99 basis points	(7,124)
January 2006 January 2016	$ 250,000,000	6.625%	6 month LIBOR plus 129 basis points	(3,178)
March 2006 January 2016	$ 250,000,000	6.875%	6 month LIBOR plus 120 basis points	(172)
				$ (36,763)

In the Current Period, we closed three interest rate swaps for gains totaling $3.0 million. These interest rate swaps were designated as fair value hedges, and the settlement amounts received will be amortized as a reduction to realized interest expense over the remaining terms of the related senior notes.

To mitigate our short-term exposure to rising interest rates on a portion of our long-term debt that has been converted to floating-rate, we have entered into zero-cost collar transactions. These collars contain a fixed floor rate (put) and fixed ceiling rate (call). If LIBOR exceeds the ceiling rate or falls below the floor rate, Chesapeake pays the fixed rate and receives LIBOR. If LIBOR is between the ceiling and floor rates, no payments are due from either party. As of September 30, 2006, we were a party to the following zero-cost interest rate collars:

Payment Dates	Notional Amount	LIBOR Floor	LIBOR Ceiling
July 2007 January 2010	$150,000,000	4.53%	5.37%
June 2007 December 2009	$150,000,000	4.53%	5.37%
August 2007 February 2010	$250,000,000	4.53%	5.37%
July 2007 January 2010	$250,000,000	4.53%	5.37%

ITEM 4. *Controls and Procedures*

We maintain disclosure controls and procedures designed to ensure that information required to be disclosed by Chesapeake in reports filed or submitted by it under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including our principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. At the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of Chesapeake management, including Chesapeake s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of Chesapeake s disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(b). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective.

No changes in Chesapeake s internal control over financial reporting occurred during the Current Quarter that have materially affected, or are reasonably likely to materially affect, Chesapeake s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. ***Legal Proceedings***

Chesapeake is currently involved in various disputes incidental to its business operations. Management is of the opinion that the final resolution of currently pending or threatened litigation is not likely to have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Item 1A. ***Risk Factors***

Our business has many risks. Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock, preferred stock or senior notes are described under Risk Factors in Item 1A of our annual report on Form 10-K for the year ended December 31, 2005. This information should be considered carefully, together with other information in this report and other reports and materials we file with the Securities and Exchange Commission.

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

On September 29, 2006, we issued 1,375,989 shares of our common stock to Altoma Energy, an Oklahoma general partnership, in exchange for 40,000 shares of common stock of Chaparral Energy, Inc. The Chesapeake shares were valued at $40 million, based on the average closing price during a ten trading-day period beginning September 13, 2006, and were issued in a private offering without registration under the Securities Act of 1933 in reliance on the exemption provided in Section 4(2) of such Act.

The following table presents information about repurchases of our common stock during the three months ended September 30, 2006:

Period	Total Number of Shares Purchased(a)	Average Price Paid Per Share(a)	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs(b)
July 1, 2006 through July 31, 2006	163,509	$ 29.916		
August 1, 2006 through August 31, 2006	14,645	32.411		
September 1, 2006 through September 30, 2006	2,338	28.980		
Total	180,492	$ 30.106		

(a) Includes 32 shares purchased in the open market for the matching contributions we make to our 401(k) plans, the deemed surrender to the company of 9,587 shares of common stock to pay the exercise price in connection with the exercise of employee stock options and the surrender to the company of 170,873 shares of common stock to pay withholding taxes in connection with the vesting of employee restricted stock.

(b) We make matching contributions to our 401(k) plans and 401(k) make-up plan using Chesapeake common stock which is held in treasury or is purchased by the respective plan trustees in the open market. The plans contain no limitation on the number of shares that may be purchased for purposes of company contributions.

Item 3. ***Defaults Upon Senior Securities***

Not applicable.

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

Not applicable.

Item 5. ***Other Information***

Not applicable.

Item 6. ***Exhibits***

The following exhibits are filed as a part of this report:

Exhibit Number	**Description**
3.1.1	Restated Certificate of Incorporation, as amended. Incorporated herein by reference to Exhibit 3.1.1 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.2	Certificate of Designation for Series A Junior Participating Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.2 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.3	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2003), as amended. Incorporated herein by reference to Exhibit 3.1.3 Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.4	Certificate of Designation of 4.125% Cumulative Convertible Preferred Stock, as amended. Incorporated herein by reference to Exhibit 3.1.4 to Chesapeake s quarterly report on Form 10-Q for the quarter ended June 30, 2006.
3.1.5	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005B). Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed November 9, 2005.
3.1.6	Certificate of Designation of 5% Cumulative Convertible Preferred Stock (Series 2005), as amended. Incorporated herein by reference to Exhibit 3.1.6 to Chesapeake s Form 10-Q for the quarter ended March 31, 2005.
3.1.7	Certificate of Designation of 4.5% Cumulative Convertible Preferred Stock. Incorporated herein by reference to Exhibit 3.1 to Chesapeake s current report on Form 8-K filed September 15, 2005.
3.2	Bylaws, as amended and restated. Incorporated herein by reference to Exhibit 3.2 to Chesapeake s annual report on Form 10-K for the year ended December 31, 2003.
4.1.1*	Eighth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of May 27, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2014.
4.2.1*	Eighth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of August 2, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.00% senior notes due 2014.
4.3.1*	Twelfth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of December 20, 2002 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.75% senior notes due 2015.

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Exhibit Number	Description
4.5.1*	Commitment Increase Agreement dated September 1, 2006, by and among Chesapeake Energy Corporation, Chesapeake Exploration Limited Partnership and Chesapeake Appalachia, L.L.C., as Co-Borrowers, Union Bank of California, N.A., as administrative agent and the several lenders party thereto.
4.6.1*	Eleventh Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of March 5, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.50% senior notes due 2013.
4.7.1*	Ninth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of November 26, 2003 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2016.
4.8.1*	Seventh Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of December 8, 2004 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.375% senior notes due 2015.
4.9.1*	Fifth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.
4.10.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
4.11.1*	Fifth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of August 16, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.50% senior notes due 2017.
4.12.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.875% senior notes due 2020.
4.13.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of November 8, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 2.75% contingent convertible senior notes due 2035.
4.14.1*	First Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of June 30, 2006 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 7.625% senior notes due 2013.
10.1.1 *	Chesapeake s 2003 Stock Incentive Plan, as amended.
10.1.3 *	Chesapeake s 1994 Stock Option Plan, as amended.
10.1.4 *	Chesapeake s 1996 Stock Option Plan, as amended.
10.1.5 *	Chesapeake s 1999 Stock Option Plan, as amended.

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Exhibit Number	Description
10.1.6 *	Chesapeake s 2000 Employee Stock Option Plan, as amended.
10.1.8 *	Chesapeake s 2001 Stock Option Plan, as amended.
10.1.10 *	Chesapeake s 2001 Nonqualified Stock Option Plan, as amended.
10.1.11 *	Chesapeake s 2002 Stock Option Plan, as amended.
10.1.13 *	Chesapeake s 2002 Nonqualified Stock Option Plan, as amended.
10.2.2	Employment Agreement dated as of October 1, 2006 between Marcus C. Rowland and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.2 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.3	Employment Agreement dated as of October 1, 2006 between Steven C. Dixon and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.3 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.4	Employment Agreement dated as of October 1, 2006 between J. Mark Lester and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.4 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.5	Employment Agreement dated as of October 1, 2006 between Douglas J. Jacobson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.5 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.6	Employment Agreement dated as of October 1, 2006 between Martha A. Burger and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.6 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.7	Employment Agreement dated as of October 1, 2006 between Henry J. Hood and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.7 to Chesapeake s current report on Form 8-K filed October 5, 2006.
10.2.8	Employment Agreement dated as of October 1, 2006 between Michael A. Johnson and Chesapeake Energy Corporation. Incorporated herein by reference to Exhibit 10.2.8 to Chesapeake s current report on Form 8-K filed October 5, 2006.
12*	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends.
31.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Marcus C. Rowland, Executive Vice President and Chief Financial Officer, Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Aubrey K. McClendon, Chairman and Chief Executive Officer, Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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* Filed herewith.
Management contract or compensatory plan or arrangement

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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.

CHESAPEAKE ENERGY CORPORATION
(Registrant)

By: /s/ AUBREY K. MCCLENDON
Aubrey K. McClendon

Chairman of the Board and

Chief Executive Officer

By: /s/ MARCUS C. ROWLAND
Marcus C. Rowland

Executive Vice President and

Chief Financial Officer

Date: November 7, 2006

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4.9.1*	Fifth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of April 19, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.625% senior notes due 2016.
4.10.1*	Fourth Supplemental Indenture dated as of October 18, 2006 to Indenture dated as of June 20, 2005 among Chesapeake, as issuer, its subsidiaries signatory thereto, as Subsidiary Guarantors, and The Bank of New York Trust Company, N.A., as Trustee, with respect to the 6.25% senior notes due 2018.
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Management contract or compensatory plan or arrangement