ENCORE ACQUISITION CO
Form 10-Q
August 08, 2006

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D. C. 20549
FORM 10-Q

(Mark One)

þ **Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the quarterly period ended June 30, 2006

or

o **Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
For the transition period from __________ to __________

Commission file number 1-16295
ENCORE ACQUISITION COMPANY
(Exact name of registrant as specified in its charter)

Delaware	**75-2759650**
(State or other jurisdiction of incorporation)	(IRS Employer Identification No.)
777 Main Street, Suite 1400, Fort Worth, Texas	**76102**
(Address of principal executive offices)	(Zip Code)

Registrant s telephone number, including area code: **(817) 877-9955**
Not applicable
(Former name, former address and former fiscal year, if changed since last report)

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 þ No o

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o

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

Number of shares of common stock, $0.01 par value, outstanding as of August 3, 2006.................52,969,984

ENCORE ACQUISITION COMPANY
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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q and other materials filed with the Securities and Exchange Commission, or in other written or oral statements made or to be made by us, other than statements of historical fact, are forward-looking statements as defined by the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These forward-looking statements give our current expectations or forecasts of future events. You can identify our forward-looking statements by the fact that they do not relate strictly to historical or current facts. These statements may include words such as anticipate, estimate, expect, project, intend, plan, should, forecast, budget and other words and terms of similar meaning. Our actual results may differ significantly from the results discussed in the forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, the matters discussed in Item 1A. Risk Factors in our Annual Report on Form 10-K for the fiscal year ended December 31, 2005 and in our other filings with the SEC. If one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated. You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement. We undertake no responsibility to update forward-looking statements for changes related to these or any other factors that may occur subsequent to this filing for any reason.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

ENCORE ACQUISITION COMPANY
CONSOLIDATED BALANCE SHEETS
(in thousands except shares and per share amounts)

	June 30, 2006 (unaudited)	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 663	$ 1,654
Accounts receivable	74,954	76,960
Inventory	15,868	11,231
Derivatives	9,388	8,826
Deferred taxes	26,331	29,030
Other	6,430	5,656
Total current assets	133,634	133,357
Properties and equipment, at cost successful efforts method:		
Proved properties	1,841,320	1,691,175
Unproved properties	47,513	37,646
Accumulated depletion, depreciation, and amortization	(309,409)	(255,564)
	1,579,424	1,473,257
Other property and equipment	17,099	15,894
Accumulated depreciation	(6,410)	(5,366)
	10,689	10,528
Goodwill	57,839	59,046
Derivatives	7,719	17,316
Other	15,512	12,201
Total assets	$ 1,804,817	$ 1,705,705
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 10,247	$ 27,281
Accrued and other current	76,765	86,399
Derivatives	60,405	68,850

Deferred premiums on derivative contracts	14,636	7,665
Total current liabilities	162,053	190,195
Derivatives	28,646	44,087
Future abandonment cost	15,089	14,430
Deferred taxes	247,665	213,268
Long-term debt	593,439	673,189
Deferred premiums on derivative contracts	15,217	22,476
Other	1,219	1,279
Total liabilities	1,063,328	1,158,924
Commitments and contingencies		
Stockholders equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none issued and outstanding		
Common stock, $.01 par value, 144,000,000 shares authorized, 52,964,384 and 48,784,846 issued and outstanding, respectively	530	488
Additional paid-in capital	451,626	316,619
Treasury stock, at cost, of 6,553 and 11,169 shares, respectively	(176)	(375)
Retained earnings	342,810	302,875
Accumulated other comprehensive income	(53,301)	(72,826)
Total stockholders equity	741,489	546,781
Total liabilities and stockholders equity	$ 1,804,817	$ 1,705,705

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
(in thousands except per share amounts)
(unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2006	**2005**	**2006**	**2005**
Revenues:				
Oil	$ 94,128	$ 69,559	$ 172,814	$ 136,695
Natural gas	39,343	30,158	76,873	54,603
Total revenues	133,471	99,717	249,687	191,298
Expenses:				
Production -				
Lease operations	23,118	16,068	45,854	31,217
Production, ad valorem, and severance taxes	12,580	9,813	24,822	18,899
Depletion, depreciation, and amortization	27,988	19,038	55,008	35,721
Exploration	4,016	3,785	6,025	6,408
General and administrative	5,421	4,217	11,949	8,332
Derivative fair value loss	10,794	1,692	13,100	4,101
Other operating	1,960	1,703	4,489	3,302
Total expenses	85,877	56,316	161,247	107,980
Operating income	47,594	43,401	88,440	83,318
Other income (expenses):				
Interest	(10,718)	(7,448)	(22,505)	(14,407)
Other	428	85	549	149
Total other income (expenses)	(10,290)	(7,363)	(21,956)	(14,258)
Income before income taxes	37,304	36,038	66,484	69,060
Current income tax provision	(820)	(589)	(1,102)	(1,390)
Deferred income tax provision	(14,249)	(11,781)	(25,211)	(22,218)
Net income	$ 22,235	$ 23,668	$ 40,171	$ 45,452
Net income per common share:				
Basic	$ 0.42	$ 0.49	$ 0.79	$ 0.93
Diluted	0.42	0.48	0.78	0.92

Weighted average common shares outstanding:				
Basic	52,631	48,660	50,724	48,636
Diluted	53,532	49,458	51,663	49,429

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
June 30, 2006
(in thousands)
(unaudited)

	Shares of Common Stock	Common Stock	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Stockholders Equity
Balance at December 31, 2005	48,785	$ 488	$ 316,619	(11)	$ (375)	$ 302,875	$ (72,826)	$ 546,781
Exercise of stock options and vesting of restricted stock	190	2	2,998					3,000
Purchase of treasury stock				(7)	(176)			(176)
Cancellation of treasury stock	(11)		(139)	11	375	(236)		
Issuance of common stock	4,000	40	126,850					126,890
Non-cash stock based compensation			5,298					5,298
Components of comprehensive income:								
Net income						40,171		40,171
Change in deferred hedge gain/loss (Net of income taxes of $11,631)							19,525	19,525
Total comprehensive income								59,696
Balance at June 30, 2006	52,964	$ 530	$ 451,626	(7)	$ (176)	$ 342,810	$ (53,301)	$ 741,489

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

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ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(unaudited)

	Six months ended June 30, 2006	Six months ended June 30, 2005
Operating activities		
Net income	$ 40,171	$ 45,452
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and amortization expense	55,008	35,721
Dry hole expense	2,580	3,329
Deferred tax expense	25,211	22,218
Non-cash stock based compensation expense	4,853	1,779
Non-cash derivative loss	19,099	8,278
Other non-cash expense	2,954	1,844
Loss on disposition of assets	472	160
Changes in operating assets and liabilities:		
Accounts receivable	2,205	(7,059)
Other assets	(10,323)	(7,065)
Accounts payable	(1,428)	7,716
Other liabilities	(9,326)	5,092
Cash provided by operating activities	131,476	117,465
Investing Activities		
Purchases of other property and equipment	(2,515)	(4,714)
Acquisition of oil and natural gas properties	(15,917)	(17,379)
Development of oil and natural gas properties	(146,959)	(144,434)
Other	(984)	424
Cash used by investing activities	(166,375)	(166,103)
Financing Activities		
Proceeds from issuance of common stock	128,000	
Offering costs paid	(1,110)	
Proceeds from long-term debt	104,000	195,000
Payments on long-term debt	(184,000)	(134,000)
Cash overdrafts	(15,606)	(13,362)
Exercise of stock options and other	2,624	920
Cash provided by financing activities	33,908	48,558
Decrease in cash and cash equivalents	(991)	(80)
Cash and cash equivalents, beginning of period	1,654	1,103

Cash and cash equivalents, end of period	$	663	$	1,023

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

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ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2006
(unaudited)

1. Formation of Encore

Encore Acquisition Company, a Delaware corporation (Encore or the Company), is a growing independent energy company engaged in the acquisition, development, exploitation, exploration, and production of onshore North American oil and natural gas reserves. Since the Company s inception in 1998, Encore has sought to acquire high-quality assets with potential for upside through drilling, waterflood, and tertiary projects. Encore s properties currently are located in four core areas: the Cedar Creek Anticline (CCA) in the Williston Basin of Montana and North Dakota; the Permian Basin of western Texas and southeastern New Mexico; the Mid-Continent area, which includes the Arkoma and Anadarko Basins of Oklahoma, the North Louisiana Salt Basin, the East Texas Basin, and the Barnett Shale of northern Texas; and the Rockies, which includes non-CCA assets in the Williston and Powder River Basins of Montana and North Dakota, and the Paradox Basin of southeastern Utah.

2. Basis of Presentation

In the opinion of management, the accompanying unaudited consolidated financial statements of Encore include all adjustments necessary to present fairly, in all material respects, our financial position as of June 30, 2006, results of operations for the three and six months ended June 30, 2006 and 2005, and cash flows for the six months ended June 30, 2006 and 2005. All adjustments are of a recurring nature. These interim results are not necessarily indicative of results for an entire year.

Certain amounts and disclosures have been condensed or omitted from these consolidated financial statements pursuant to the rules and regulations of the Securities and Exchange Commission. Therefore, these consolidated financial statements should be read in conjunction with the consolidated financial statements and related notes thereto included in the Company s 2005 Annual Report on Form 10-K.

Stock-based Compensation

On January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 123R, *Share-Based Payment*. SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees* (APB No. 25). SFAS No. 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. See Note 11. Incentive Stock Plan for more information.

New Accounting Standards

Emerging Issues Task Force (EITF) Issue 04-13 Accounting for Purchases and Sales of Inventory with the Same Counterparty

The Emerging Issues Task Force considered Issue No. 04-13 in its May 17, 2005 and June 16, 2005 meetings to discuss inventory sales to another entity in the same line of business from which the selling entity also purchases inventory. The Task Force reached consensus on the issue that purchases and sales of inventory with the same counterparty should be combined as a single nonmonetary transaction (net) and noted factors that may indicate that transactions were entered into in contemplation of one another. The Task Force also concluded that transfers of finished goods inventory in exchange for work-in-progress or raw materials should be recognized at fair value and prescribes additional disclosures. The Task Force ratified Issue No. 04-13 at its September 28, 2005 meeting, which should be applied to new arrangements entered into in the first interim or annual reporting period beginning after March 15, 2006. The Company has previously reported transactions of this nature on a net basis; therefore, the adoption of Issue No. 04-13 did not have a material impact on the Company s financial condition, results of operations, or cash flows.

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FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes*. The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* The interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 is effective for fiscal years beginning after December 15, 2006 and is not expected to have a material impact on the Company s financial condition, results of operations, or cash flows.

3. Inventories

Inventories are comprised principally of materials and supplies and oil in pipelines, which are stated at the lower of cost (determined on an average basis) or market. The Company s inventories consisted of the following as of the dates indicated (amounts in thousands):

	June 30, 2006	December 31, 2005
Warehouse inventory	$ 10,653	$ 9,019
Oil in pipelines	5,215	2,212
Total	$ 15,868	$ 11,231

4. Crusader Acquisition and Goodwill

On October 14, 2005, the Company purchased all of the outstanding capital stock of Crusader Energy Corporation (Crusader), a privately held, independent oil and natural gas company, for a purchase price of approximately $109.6 million, which includes cash paid to Crusader s former shareholders of $79.2 million, the repayment of $29.7 million of Crusader s debt, and transaction costs incurred of $0.7 million.

The calculation of the total purchase price and the estimated allocation as of June 30, 2006 to the fair value of net assets acquired at October 14, 2005, are as follows (in thousands):

Calculation of total purchase price:

Cash paid to Crusader s former owners	$ 79,142
Crusader debt repaid	29,732
Transaction costs	702
Total purchase price	$ 109,576

Allocation of purchase price to the fair value of assets acquired:

Cash	$ 18,592
Current assets, excluding cash	3,329
Proved oil and gas properties	85,388
Unproved oil and gas properties	6,863
Goodwill	19,931
Total assets acquired	134,103

Current liabilities	(7,477)
Non-current liabilities	(1,190)
Deferred income taxes	(15,860)
Total liabilities assumed	(24,527)
Fair value of net assets acquired	$ 109,576

The purchase price allocation resulted in $19.9 million of goodwill primarily as the result of the difference between the fair value of acquired oil and natural gas properties and their lower carryover tax basis, which resulted in deferred taxes of $15.9 million. Management believes the goodwill will be recovered through operating synergies resulting from the close proximity of the properties acquired to our existing operations. None of the goodwill is deductible for income tax purposes.

5. Derivative Financial Instruments

Commodity Contracts Hedge Accounting

The Company has used hedge accounting for certain of its derivative contracts, whereby the effective portion of changes in the fair value of the contract was deferred in accumulated other comprehensive income rather than recognized in current period earnings. Settlements on these contracts were included in revenue with the revenue from the hedged production in the period of settlement.

The following tables summarize the Company s open commodity derivative instruments designated as hedges as of June 30, 2006:

Oil Derivative Instruments at June 30, 2006 Designated as Hedges

Period	Daily Floor Volume (Bbl)	Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Swap Price (per Bbl)	Fair Market Value (in thousands)
July Dec. 2006	1,500	$40.00		$	500	$62.09	$ (1,217)
Jan. Dec. 2007	3,000	51.67			500	60.84	(1,525)
Jan. June 2008	4,000	60.00			500	59.64	983

Natural Gas Derivative Instruments at June 30, 2006 Designated as Hedges

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (in thousands)
July Dec. 2006	25,000	$6.36		$	12,500	$5.08	$ 667
Jan. Dec. 2007	20,000	6.96			10,000	4.99	(6,509)

Commodity Contracts Mark-to-Market Accounting: Previously designated as hedges

In the second quarter of 2006, the Company discontinued hedge accounting for certain contracts that were previously used to hedge oil production in the CCA and natural gas production in the North Louisiana Salt Basin. These contracts no longer qualified for hedge accounting due to significant fluctuations between the wellhead prices the Company received in those areas and NYMEX, the basis of the derivative contracts affected. The following tables summarize the Company s derivative contracts on which hedge accounting was discontinued in the second quarter of 2006.

Oil Derivative Instruments at June 30, 2006 Undesignated

Period	Daily Floor Volume (Bbl)	Floor Price (per Bbl)	Daily Cap Volume (Bbl)	Cap Price (per Bbl)	Daily Swap Volume (Bbl)	Swap Price (per Bbl)	Fair Market Value (in thousands)
July Dec. 2006	11,500	$45.65	1,000	$29.88	2,500	$32.30	$(27,726)
Jan. Dec. 2007	5,000	55.00			2,500	31.94	(35,800)
Jan. June 2008					500	57.53	(1,387)

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Natural Gas Derivative Instruments at June 30, 2006 Undesignated

Period	Daily Floor Volume (Mcf)	Floor Price (per Mcf)	Daily Cap Volume (Mcf)	Cap Price (per Mcf)	Daily Swap Volume (Mcf)	Swap Price (per Mcf)	Fair Market Value (in thousands)
July Dec. 2006	7,500	$5.57	5,000	$5.68		$	$ (1,094)
Jan. Dec. 2007	2,500	7.00					490

For derivative contracts that no longer qualify for hedge accounting, we marked the contracts to market as of April 1, 2006. The cumulative deferred gain (loss) on the contracts from inception to April 1, 2006, based on the change in the contracts fair value less previously recorded ineffectiveness, was recorded in accumulated other comprehensive income and will be amortized to revenue as the contracts settle. Any further changes in the fair value of these contracts will be recorded in derivative fair value gain (loss), as will the amount by which actual settlements differ from the expected amounts recorded in accumulated other comprehensive income at April 1, 2006.

Commodity Contracts Mark-to-Market Accounting: Basis Swaps

In addition, in order to more effectively hedge the cash flows received on oil and natural gas production, the Company enters into financial instruments, commonly called basis swaps, whereby Encore swaps certain per Bbl or per Mcf floating market indices for a fixed amount. These market indices are a component of the price the Company is paid on its actual production and by fixing this component of the Company s marketing price, Encore is able to realize a net price with a more consistent differential to NYMEX. Since NYMEX is the basis of all the Company s derivative oil hedging contracts and some of the Company s natural gas contracts, a more consistent differential results in more effective hedges. However, management has elected not to use hedge accounting for certain of these contracts. Instead, the Company marks these contracts to market each quarter through Derivative fair value (gain) loss in the Consolidated Statements of Operations. Thus, as these contracts do not change the Company s overall hedged volumes, average prices presented in the table above are exclusive of any effect of these non-hedge instruments. As of June 30, 2006, the mark-to-market value of these basis swap contracts was a $1.2 million asset.

Commodity Contracts Current Period Impact

As a result of hedging transactions for oil and natural gas, the Company recognized a pre-tax reduction in revenues of approximately $31.3 million and $23.7 million in the six months ended June 30, 2006 and 2005, respectively. The Company also recognized in its Consolidated Statement of Operations derivative fair value gains and losses related to (1) ineffectiveness of derivative contracts designated as hedges; (2) changes in the market value of basis swaps and certain other commodity derivatives that are not designated as hedges; and (3) settlements on derivative contracts not designated as hedges. The following table summarizes the components of derivative fair gains and losses for the six months ended June 30, 2006 and 2005 (in thousands):

	Six months ended June 30, 2006	Six months ended June 30, 2005	*Increase / (Decrease)*
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$ 1,748	$ 4,667	*$ (2,919)*
Undesignated derivative contracts:			
Mark-to-market (gain) loss:			
Interest rate swap		150	*(150)*
Commodity contracts	12,369		*12,369*
Settlements of commodity contracts	(1,017)	(716)	*(301)*
Total derivative fair value loss	$ 13,100	$ 4,101	*$ 8,999*

The actual gains or losses the Company realizes from derivative transactions may vary significantly from the deferred loss amount recorded in accumulated other comprehensive income at June 30, 2006 due to the fluctuation of prices in the commodities markets.

The Company had $29.9 million of derivative premiums payable recorded at June 30, 2006, of which $15.2 million is considered long-term and is recorded in Deferred premiums on derivatives contracts in the Company s Consolidated Balance

Sheet. The premiums relate to various oil and natural gas floor contracts and are payable on a monthly basis from July 2006 to June 2008.

6. Asset Retirement Obligations

The Company s primary asset retirement obligations relate to future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The following table summarizes the changes in the Company s future abandonment liability recorded in Future abandonment costs on the Company s Consolidated Balance Sheet for the period from January 1, 2006 through June 30, 2006 (in thousands):

	Six months ended June 30, 2006
Future abandonment liability at January 1, 2006	$ 14,430
Wells drilled	72
Accretion expense	330
Plugging and abandonment costs incurred	(779)
Revision of estimates	1,036
Future abandonment liability at June 30, 2006	$ 15,089

7. Debt

The Company s long-term debt consisted of the following as of the dates indicated (amounts in thousands):

	June 30, 2006	December 31, 2005
Revolving credit facility	$	$ 80,000
$6^1/4$% Notes	150,000	150,000
6% Notes, net of unamortized discount of $5,108 and $5,317, respectively	294,892	294,683
$7^1/4$% Notes, net of unamortized discount of $1,453 and $1,494, respectively	148,547	148,506
Total	$ 593,439	$ 673,189

The Company had $55.0 million of outstanding letters of credit at June 30, 2006. These letters of credit are posted primarily with two counterparties to the Company s hedging contracts and are used in lieu of cash margin deposits with those counterparties. Any outstanding letters of credit reduce the availability under the Company s revolving credit facility. As a result, the Company s availability under its revolving credit facility was reduced to $495.0 million at June 30, 2006. On April 4, 2006, the Company closed a public offering of its common stock for net proceeds of approximately $126.9 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. The proceeds were used to reduce the amounts outstanding under the Company s revolving credit facility, to invest in oil and natural gas activities, and to pay general corporate expenses. See Note 10. Public Offering of Common Stock for more information.

8. Income Taxes

Reconciliation of income tax expense with tax at the Federal statutory rate is as follows (in thousands):

	Six months ended June 30,	
	2006	2005
Income before income taxes	$ 66,484	$ 69,060

Tax at statutory rate	$ 23,269	$ 24,171
State income taxes, net of federal benefit	1,550	1,371
Enactment of the Texas Margin Tax	1,295	
Section 43 credits		(1,446)
Permanent and other	199	(488)
Income tax provision	$ 26,313	$ 23,608

The Company s effective tax rate increased to 39.6% for the six months ended June 30, 2006, as compared to 34.2% for the six months ended June 30, 2005. The Enhanced Oil Recovery credits available under Section 43 are fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during the six months ended June 30, 2006. In addition, a Texas franchise tax reform measure was signed into law on May 18, 2006 that revised the computation of the Texas franchise tax to now be applicable to numerous types of entities that previously were not subject to the tax. The Company adjusted its net deferred tax balances using the new higher marginal tax rate it expects to be effective when those deferred taxes become current. This resulted in a charge of $1.3 million during the six months ended June 30, 2006.

9. Earnings Per Share (EPS)

The following table sets forth basic and diluted EPS computations for the three and six months ended June 30, 2006 and 2005 (in thousands, except per share data):

	Three months ended June 30,		Six months ended June 30,	
	2006	**2005**	**2006**	**2005**
Numerator:				
Net income	$ 22,235	$ 23,668	$ 40,171	$ 45,452
Denominator:				
Denominator for basic earnings per share -				
Weighted average shares outstanding	52,631	48,660	50,724	48,636
Effect of dilutive options and diluted restricted stock (a)	901	798	939	793
Denominator for diluted earnings per share	53,532	49,458	51,663	49,429
Net income per common share:				
Basic	$ 0.42	$ 0.49	$ 0.79	$ 0.93
Diluted	$ 0.42	$ 0.48	$ 0.78	$ 0.92

(a) For the quarters ended June 30, 2006 and 2005, there were 107,360 and 114,375 employee stock options that were excluded from the calculation of diluted earnings per share because their effect would have been antidilutive.

10. Public Offering of Common Stock

On April 4, 2006, the Company closed a public offering of 4.0 million shares of the Company s common stock at a price of $32.00 per share. The shares were sold under a shelf registration statement filed with the Securities and Exchange Commission in June 2004. The net proceeds of the offering, after deducting underwriting discounts and commissions and the estimated expenses of the offering, were approximately $126.9 million. The Company used the net proceeds to reduce the amounts outstanding under its revolving credit facility, to invest in oil and natural gas activities, and to pay general corporate expenses.

11. Incentive Stock Plan

During 2000, the Company s Board of Directors and stockholders approved the 2000 Incentive Stock Plan (the Plan). The original plan was amended and restated effective March 18, 2004. The purpose of the Plan is to attract, motivate, and retain selected employees of the Company and to provide the Company with the ability to provide incentives more directly linked to the profitability of the business and increases in shareholder value. All directors and full-time regular employees of the Company and its subsidiaries and affiliates are eligible to be granted awards under the Plan. The total number of shares of common stock reserved for issuance pursuant to the Plan is 4,500,000. As of June 30, 2006, there were 1,285,109 shares remaining under the Plan. The Plan provides for the granting of cash awards, incentive stock options, non-qualified stock options, restricted stock, and stock appreciation rights at the discretion of the Compensation Committee of the Company s Board of Directors.

The Plan contains the following individual limits:

- an employee may not be awarded more than 150,000 shares of common stock in any calendar year;
- a nonemployee director may not be awarded more than 10,000 shares of common stock in any calendar year; and
- an employee may not receive awards consisting of cash (including cash awards that are granted as performance awards) in respect of any calendar year having a value determined on the grant date in excess of $1.0 million.

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All options that have been granted under the Plan have a strike price at least equal to the market price. Additionally, all options have a ten-year life and vest equally over a three-year period. Restricted stock granted under the Plan vests over varying periods from one to five years, subject to performance-based vesting for certain members of senior management.

Adoption of SFAS No. 123R   Share-Based Payment

On January 1, 2006, the Company adopted the provisions of SFAS No. 123R, *Share-Based Payment*. SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB No. 25, *Accounting for Stock Issued to Employees*. SFAS No. 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards.

The Company adopted the provisions of SFAS No. 123R using the modified prospective method, under which compensation cost is recognized in the financial statements for (1) share-based payments granted after January 1, 2006 based on the requirements of SFAS 123R, and (2) all unvested awards granted prior to January 1, 2006 based on criteria established in SFAS No. 123, *Accounting for Stock-Based Compensation*. As a result, the Company did not record a cumulative effect of accounting change related to the adoption.

Under SFAS No. 123R, equity instruments are not considered issued until all vesting conditions lapse. This differs from APB No. 25, which required the recording of restricted stock to equity with an off-setting contra-equity account which was amortized to expense over the vesting period. Because unvested restricted stock is no longer considered issued, the contra-equity account, Deferred Compensation, is no longer reported as a separate component of equity. Certain equity balances as originally reported in the Company s 2005 Annual Report on Form 10-K have been retroactively restated to reflect the change. The following table summarizes the balances at December 31, 2005 as originally reported and as restated (in thousands):

	December 31, 2005	
	As Originally Reported	As Restated
Shares of common stock outstanding	49,368	48,785
Common stock	$ 494	$ 488
Additional paid-in capital	325,620	316,619
Deferred compensation	(9,007)	
Total stockholders equity	546,781	546,781

As a result of adopting SFAS No. 123R on January 1, 2006, the Company s income before income taxes and net income for the six months ended June 30, 2006, are $0.7 million and $0.5 million lower, respectively, than if it had continued to account for share-based compensation under APB Opinion 25. Basic and diluted earnings per share for the six months ended June 30, 2006 are $0.01 and $0.01 lower, respectively, than if the Company had continued to account for share-based compensation under APB Opinion 25.

The compensation cost and income tax benefit, related to the Company s incentive stock plan that has been recorded in the statement of operations for the six months ended June 30, 2006 was $4.9 million and $1.8 million, respectively. During the six months ended June 30, 2006, the Company also capitalized $0.4 million of stock-based compensation cost as a component of Properties and equipment . Stock-based compensation expense has been allocated to lease operations expense, general and administrative expense, and exploration expense based on the allocation of the respective cash compensation. Amounts in the 2005 statement of operations have been reclassified to conform to the 2006 presentation.

Stock Options

The fair value of each option award granted during the six months ended June 30, 2006 and 2005 was estimated on the date of grant using a Black-Scholes option valuation model based on the assumptions noted in the following table. The expected volatility is based on a combination of the historical volatility of the Company s stock and the historical stock volatility of certain peer companies for a period of time commensurate with the expected term of the award. For options granted in the six months ended June 30, 2006, the Company used the simplified method, prescribed by SEC Staff Accounting Bulletin No. 107, to estimate the expected term of the options. The risk-free rate is based on the U.S Treasury yield curve in effect at the time of grant for periods commensurate with the expected terms of the options.

	Six months ended June 30, 2006	2005
Expected volatility	42.8%	46.0%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	6.0	6.0
Risk-free interest rate	4.6%	3.7%

A summary of options outstanding as of June 30, 2006, and changes during the six months then ended is presented below:

	Number of Options	Weighted Average Strike Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (in thousands)
Outstanding at January 1, 2006	1,440,812	$ 13.20		
Granted	122,890	31.10		
Forfeited	(45,133)	24.32		
Exercised	(162,798)	12.63		
Outstanding at June 30, 2006	1,355,771	14.52	6.5	$ 17,142
Exercisable at June 30, 2006	1,085,465	11.98	6.0	16,114

The weighted average fair value of individual options granted during the six months ended June 30, 2006 was $14.96. The total intrinsic value of options exercised during the six months ended June 30, 2006 and 2005 was $2.3 million and $1.6 million, respectively. The Company received proceeds from the exercise of stock options of $2.1 million and $0.8 million and realized a tax benefit related to the exercises of $0.9 million and $0.1 million during the six months ended June 30, 2006 and 2005, respectively. At June 30, 2006, the Company had $2.5 million of total unrecognized compensation cost related to unvested stock options. That cost is expected to be recognized over a weighted average period of 2.0 years.

Restricted Stock

As of June 30, 2006, there were 853,669 shares of unvested restricted stock outstanding, dependent only on continued employment for vesting. Of this amount, 339,915 shares were granted during the six months ended June 30, 2006. Additionally, as of June 30, 2006, there were 67,202 shares of unvested restricted stock outstanding that depend on continued employment and certain performance measures for vesting, all of which were granted during the six months ended June 30, 2006.

A summary of the status of the Company s unvested restricted stock outstanding as of June 30, 2006, and changes during the six months then ended, is presented below:

	Number of Shares	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2006	583,274	$ 20.53
Granted	428,609	31.17

Vested	(27,909)	18.60
Forfeited	(63,103)	24.22
Outstanding at June 30, 2006	920,871	25.29

As of June 30, 2006, there was $13.4 million of total unrecognized compensation cost related to unvested, outstanding restricted stock. That cost is expected to be recognized over a weighted average period of 3.3 years. During the six months ended June 30, 2006 and 2005, there were 27,909 shares and 28,590 shares, respectively, that became vested. Employees elected to satisfy minimum tax withholding obligations related to the vested restricted stock by allowing the Company to withhold 6,553 and 7,128 shares of common stock during the six months ended June 30, 2006 and 2005, respectively.

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12. Comprehensive Income (Loss)

Components of comprehensive income (loss), net of related tax, are as follows (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2006	2005	2006	2005
Net income	$ 22,235	$ 23,668	$ 40,171	$ 45,452
Change deferred loss on commodity derivatives	11,304	3,383	19,554	(30,156)
Change in deferred gain on interest rate swap	(15)	(317)	(29)	(262)
Comprehensive income (loss)	$ 33,524	$ 26,734	$ 59,696	$ 15,034

The components of accumulated other comprehensive loss, net of related tax, are as follows (in thousands):

	June 30, 2006	December 31, 2005
Deferred loss on commodity derivatives	$ (53,364)	$ (72,918)
Deferred gain on interest rate swap	63	92
Accumulated other comprehensive income	$ (53,301)	$ (72,826)

13. Financial Statements of Subsidiary Guarantors

As of June 30, 2006, all of the Company s subsidiaries were subsidiary guarantors of the Company s outstanding $6^1/4$%, 6%, and $7^1/4$% notes. Since (i) each subsidiary guarantor is 100% owned by the Company, (ii) the Company has no assets or operations that are independent of its subsidiaries, (iii) the subsidiary guarantees are full and unconditional and joint and several and (iv) all of the Company s subsidiaries are subsidiary guarantors, the Company has not included the financial statements of each subsidiary in this report. The subsidiary guarantors may, without restriction, transfer funds to the Company in the form of cash dividends, loans, and advances.

14. Commitments and Contingencies

In March 2006, the Company entered into a joint development agreement with a major oil company to develop seven natural gas fields in West Texas. The Company is required to drill a total of 24 commitment wells and may be required to advance funds to pay the partner s 70% share of drilling costs for each well. Should the Company advance funds, repayment will only be made through the monthly receipt of future proceeds of oil and natural gas sales.

15. Related Party Transactions

The Company paid $1.6 million and $0.4 million to affiliates of Hanover Compressor Company in the six months ended June 30, 2006 and 2005, respectively, for field compression services. Mr. I. Jon Brumley, the Company s Chairman, also serves as a director of Hanover Compressor Company.

16. Subsequent Event

During July 2006, the Company elected to discontinue hedge accounting prospectively for all commodity derivatives which were previously accounted for as hedges. While this change will have no effect on cash flows, future results of operations will be affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. As of July 2006, all remaining derivative contracts accounted for as hedges in the second quarter of 2006 were dedesignated. At this point, the gain (loss) to be amortized to revenue is established and deferred in accumulated other comprehensive income included in stockholders equity. All prospective mark-to-market gains and losses will be recognized in earnings rather than deferring such amounts in accumulated other comprehensive income on the balance sheet.

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

This document contains forward-looking statements, which give our current expectations or forecasts of future events. Actual results may differ materially from those discussed in our forward-looking statements due to many factors, including, but not limited to, those set forth under Item 1A. Risk Factors in Encore s 2005 Annual Report on Form 10-K. The following discussion should be read in conjunction with the consolidated financial statements and notes thereto included in this document and Encore s 2005 Form 10-K.

Introduction

This management s discussion and analysis of financial condition and results of operations is intended to provide investors with information regarding our financial condition and results of operations. The following will be discussed and analyzed:

- Second Quarter 2006 Highlights
- Results of Operations
  - Comparison of Quarter Ended June 30, 2006 to Quarter Ended June 30, 2005
  - Comparison of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2005
- Capital Resources
- Capital Commitments
- Liquidity
- Contingencies

Second Quarter 2006 Highlights

Our financial and operating results for the quarter ended June 30, 2006 included the following highlights:

- During the second quarter of 2006, we had oil and natural gas revenues of $133.5 million. This represents a 34% increase over the $99.7 million of oil and natural gas revenues reported for the second quarter of 2005.

- Our realized average oil price for the second quarter of 2006, including the effects of hedging, increased $10.97 per Bbl to $51.93 per Bbl as compared to $40.96 per Bbl in the second quarter of 2005. Our realized average natural gas price for the second quarter of 2006, including the effects of hedging, increased $0.47 per Mcf to $6.58 per Mcf as compared to $6.11 per Mcf in the second quarter of 2005.

- As expected, our oil wellhead differential to the average NYMEX price improved in the second quarter of 2006 as compared to the first quarter of 2006. The narrowing of our oil wellhead differential was due to improving market conditions in the Rocky Mountain refining area, which has positively affected the wellhead price we received on our CCA and Williston Basin properties. We expect our oil wellhead differentials to continue to narrow in the third quarter of 2006, but still remain wider than our historical average.

- Production volumes for the second quarter of 2006 increased 11% to 30,867 BOE per day (2.8 MMBOE for the quarter), compared with second quarter 2005 production of 27,697 BOE per day (2.5 MMBOE for the quarter). The rise in production volumes was attributable to our development program and acquisitions completed in the second half of 2005. The 11% increase in production volumes was attained despite a spring storm that caused a loss of power at the CCA, resulting in a shutdown of all CCA fields for four days. Oil represented 65% and 67% of our total production volumes in the second quarter of 2006 and 2005, respectively.

During the second quarter of 2006, we reported cash flows from operating activities of $76.8 million. This represents a 23% increase over the $62.6 million of cash flows from operating activities we reported for the second quarter of 2005.

We reported net income of $22.2 million, or $0.42 per diluted share, in the three months ended June 30, 2006, as compared to $23.7 million of net income, or $0.48 per diluted share, reported for the second quarter of 2005. The reduction in net income was due primarily to net derivative fair value losses of $10.8 million, or $0.13 per diluted share.

We invested $96.0 million in oil and natural gas activities during the second quarter of 2006 (excluding related asset retirement obligations). Of this amount, we invested $87.8 million in development, exploitation, high-pressure air injection (HPAI) expansion, and exploration activities, which yielded 58 gross (20.9 net) productive wells, and $8.2 million in acquiring proved properties and undeveloped leases. We operated between eight and ten drilling rigs during the second quarter of 2006, including three rigs related to our West Texas joint development agreement.

We were able to fund $76.8 million of our investments in oil and natural gas activities using operating cash flows generated during the quarter. The remaining investments were funded primarily through proceeds received from our public offering of 4.0 million shares of common stock on April 4, 2006.

On April 4, 2006, we closed a public offering of 4.0 million shares of common stock at a price of $32.00 per share. The net proceeds of the offering, after deducting underwriting discounts and commissions and the estimated expenses of the offering, were approximately $126.9 million. We used the net proceeds to reduce the amounts outstanding under our revolving credit facility, invest in oil and natural gas activities, and to pay general corporate expenses. As a result, long-term debt, net of discount, at June 30, 2006 decreased to $593.4 million from $673.2 million at December 31, 2005.

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Results of Operations

Comparison of Quarter Ended June 30, 2006 to Quarter Ended June 30, 2005

Below is a comparison of our operations during the second quarter of 2006 with the second quarter of 2005.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended June 30, 2006 and 2005, as well as each quarter s respective oil and natural gas volumes (in thousands, except per unit and per day amounts):

	Three months ended June 30, 2006	Three months ended June 30, 2005	*Increase / (Decrease)*	
Revenues:				
Oil wellhead	$ 107,459	$ 80,178	*$ 27,281*	
Oil hedges	(13,331)	(10,619)	*(2,712)*	
Total Oil Revenues	$ 94,128	$ 69,559	*$ 24,569*	*35%*
Natural gas wellhead	$ 40,758	$ 32,448	*$ 8,310*	
Natural gas hedges	(1,415)	(2,290)	*875*	
Total Natural Gas Revenues	$ 39,343	$ 30,158	*$ 9,185*	*30%*
Combined wellhead	$ 148,217	$ 112,626	*$ 35,591*	
Combined hedges	(14,746)	(12,909)	*(1,837)*	
Total Combined Revenues	$ 133,471	$ 99,717	*$ 33,754*	*34%*
Revenues ($/Unit):				
Oil wellhead	$ 59.28	$ 47.21	*$ 12.07*	
Oil hedges	(7.35)	(6.25)	*(1.10)*	
Total Oil Revenues	$ 51.93	$ 40.96	*$ 10.97*	*27%*
Natural gas wellhead	$ 6.82	$ 6.57	*$ 0.25*	
Natural gas hedges	(0.24)	(0.46)	*0.22*	
Total Natural Gas Revenues	$ 6.58	$ 6.11	*$ 0.47*	*8%*
Combined wellhead	$ 52.77	$ 44.69	*$ 8.08*	
Combined hedges	(5.25)	(5.13)	*(0.12)*	

Total Combined Revenues	$ 47.52	$ 39.56	*$ 7.96*	*20%*
Total production volumes:				
Oil (Bbls)	1,813	1,698	*115*	*7%*
Natural gas (Mcf)	5,977	4,933	*1,044*	*21%*
Combined (BOE)	2,809	2,520	*289*	*11%*
Daily production volumes:				
Oil (Bbls/day)	19,920	18,662	*1,258*	*7%*
Natural gas (Mcf/day)	65,682	54,213	*11,469*	*21%*
Combined (BOE/day)	30,867	27,697	*3,170*	*11%*
Average NYMEX Prices:				
Oil (per Bbl)	$ 70.70	$ 53.17	*$ 17.53*	*33%*
Natural gas (per Mcf)	6.65	6.95	*(0.30)*	*-4%*

Oil revenues increased $24.6 million from $69.6 million in the second quarter of 2005 to $94.1 million in the second quarter of 2006. The increase is due primarily to an increase in oil production volumes of 115 MBbls, which contributed approximately

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$5.4 million in additional revenues, and higher realized average oil prices, which contributed approximately $19.2 million in additional revenues. The increase in production volumes is the result of our development program and the integration of our 2005 acquisitions. The $19.2 million increase in revenues from higher realized average oil prices consists of a $21.9 million increase resulting from higher average wellhead oil prices, offset by increased hedging payments of $2.7 million, or $1.10 per Bbl. Our average wellhead oil price increased $12.07 per Bbl in the second quarter of 2006 over the second quarter of 2005 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $53.17 in the second quarter of 2005 to $70.70 in the second quarter of 2006. Please read the discussion below regarding the widening of our oil wellhead price to average NYMEX price differential and its related adverse impact on oil revenues for the second quarter of 2006.

Our oil wellhead revenue was reduced by $6.6 million and $3.5 million in the second quarters of 2006 and 2005, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $9.2 million from $30.1 million in the second quarter of 2005 to $39.3 million in the second quarter of 2006. The increase is due primarily to increased natural gas production volumes of 1,044 MMcf, which contributed approximately $6.9 million in additional revenues, and higher realized average natural gas prices, which contributed approximately $2.3 million in additional revenues. The $2.3 million increase in revenues from higher realized average natural gas prices consists of a $1.4 million increase resulting from higher average wellhead natural gas prices plus a decrease in hedging payments of $0.9 million, or $0.22 per Mcf. Our average wellhead natural gas price increased $0.25 per Mcf in the second quarter of 2006 over the second quarter of 2005. Although the average NYMEX price decreased $0.30 over the same periods, a significant portion of our natural gas production is based on other indices that have recently traded at premiums to the NYMEX natural gas price.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of the average NYMEX prices for the quarters ended June 30, 2006 and 2005. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended June,	
	2006	2005
Oil wellhead ($/Bbl)	$ 59.28	$ 47.21
Average NYMEX ($/Bbl)	$ 70.70	$ 53.17
Differential to NYMEX	$ (11.42)	$ (5.96)
Oil wellhead to NYMEX percentage	84%	89%
Natural gas wellhead ($/Mcf)	$ 6.82	$ 6.57
Average NYMEX ($/Mcf)	$ 6.65	$ 6.95
Differential to NYMEX	$ 0.17	$ (0.38)
Natural gas wellhead to NYMEX percentage	103%	95%

As indicated above, our oil wellhead price as a percentage of the average NYMEX price decreased to 84% in the second quarter of 2006 from 89% in the same period of 2005. The widening of the differential is due to market conditions in the Rocky Mountain refining area, which has adversely affected the wellhead price we received on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area during the first quarter of 2006, created steep pricing discounts. These discounts narrowed in the second quarter of 2006, though they are still higher than our historical average. The decrease in the oil differential percentage in the second quarter of 2006 as compared to the second quarter of 2005 adversely impacted oil revenues by $9.9 million. As Rocky Mountain refiners have completed maintenance and increased their demand for crude oil, our wellhead price as a percentage of the average NYMEX price has improved from the first quarter 2006 level of 77%.

Our natural gas wellhead price as a percentage of the average NYMEX price was 103% for the three months ended June 30, 2006, as compared to 95% for the three months ended June 30, 2005. This favorable variance is due to our natural gas production in the North Louisiana Salt Basin and Crockett County, Texas, which is sold at Katy, Houston Ship Channel, and Henry Hub natural gas prices, which have recently been higher than the average front-month NYMEX natural gas price. The increase in the natural gas differential percentage favorably impacted natural gas revenues by $3.3 million in the second quarter of 2006 as compared with the second quarter of 2005.

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Expenses. The following table summarizes our expenses for the quarters ended June 30, 2006 and 2005:

	Three months ended June 30, 2006	2005	*Increase / (Decrease)*	
Expenses (in thousands):				
Production -				
Lease operations	$ 23,118	$ 16,068	*$ 7,050*	
Production, ad valorem, and severance taxes	12,580	9,813	*2,767*	
Total production expenses	35,698	25,881	*9,817*	*38%*
Other -				
Depletion, depreciation, and amortization	27,988	19,038	*8,950*	
Exploration	4,016	3,785	*231*	
General and administrative	5,421	4,217	*1,204*	
Derivative fair value loss	10,794	1,692	*9,102*	
Other operating	1,960	1,703	*257*	
Total operating	85,877	56,316	*29,561*	*52%*
Interest	10,718	7,448	*3,270*	
Current and deferred income tax provision	15,069	12,370	*2,699*	
Total expenses	$ 111,664	$ 76,134	$ 35,530	*47%*
Expenses (per BOE):				
Production -				
Lease operations	$ 8.23	$ 6.38	*$ 1.85*	
Production, ad valorem, and severance taxes	4.48	3.89	*0.59*	
Total production expenses	12.71	10.27	*2.44*	*24%*
Other -				
Depletion, depreciation, and amortization	9.96	7.55	*2.41*	
Exploration	1.43	1.50	*(0.07)*	
General and administrative	1.93	1.68	*0.25*	
Derivative fair value loss	3.84	0.67	*3.17*	
Other operating	0.70	0.68	*0.02*	
Total operating	30.57	22.35	*8.22*	*37%*
Interest	3.82	2.96	*0.86*	
Current and deferred income tax provision	5.36	4.91	*0.45*	
Total expenses	$ 39.75	$ 30.22	$ 9.53	*32%*

Production expenses (Lease operations and production, ad valorem, and severance taxes). Total production expenses increased $9.8 million from $25.9 million in the second quarter of 2005 to $35.7 million in the second quarter of 2006. This increase resulted from an increase in total production volumes, as well as a $2.44 increase in production expenses per BOE. Total production expenses per BOE increased by a larger percentage (24%) than total revenues per BOE (20%) due to increases in the differential between the oil wellhead price we receive and the average NYMEX price in the second quarter of 2006 as compared to our historical average. As a result of these changes, our production margin (defined as revenues less production expenses) for the second quarter of 2006 increased 19% to $34.81 per BOE as compared to $29.29 per BOE for the second quarter of 2005.

The production expense attributable to lease operations increased $7.0 million from $16.1 million in the second quarter of 2005 to $23.1 million in the second quarter of 2006. The increase is due to higher production volumes, which contributed approximately $1.8 million of additional lease operations expense, and an increase in the average per BOE rate, which contributed approximately $5.2 million of additional lease operations expense. The increase in production volumes is the result of our development program and the integration of our 2005 acquisitions. The increase in our average per BOE rate of $1.85 was attributable to increases in prices paid to oilfield service companies and suppliers due to a current higher price environment, increased operational activity to maximize production, the operation of higher operating cost wells (which have become more attractive due to increases in oil and natural gas prices) and increased stock-based compensation expense attributable to equity instruments granted to employees under our 2000 Incentive Stock Plan. Prior to the adoption of SFAS 123R, non-cash stock-based compensation was separately reported on the statement of operations. Due to the adoption of SFAS 123R, non-cash stock compensation in all prior periods presented has been reclassified to allocate the amount to the same respective income statement lines as the employees salary, cash bonus, and benefits. As all full-time employees, including field personnel, are eligible for equity grants under the Company s current incentive stock plan, lease operations expense, general and administrative expense, and exploration expense have been changed to reflect the new presentation. This change has resulted in additional lease operations expense of $0.4 million in the second quarter of 2006, or $0.14 per BOE, as compared to $0.3 million in the second quarter of 2005, or $0.14 per BOE. The increase in non-cash stock-based compensation allocated to lease operations expense is primarily due to new stock-based compensation awards granted to employees in 2006.

In the third quarter of 2006, we expect lease operations expense to increase by an incremental $0.3 million from costs attributable to the Little Beaver Phase II HPAI program that previously were capitalized during the pressurization phase.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) for the second quarter of 2006 increased as compared to the same period in 2005 by $2.8 million due to an increase in production volumes and an increase in the average wellhead price we received for oil and natural production. The increase in production volumes resulted in approximately $1.1 million of additional production taxes. The average wellhead price we received for oil and natural gas production increased $8.08 per BOE, resulting in additional production taxes of approximately $1.7 million in the second quarter of 2006. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes decreased slightly from 8.7% in the second quarter of 2005 to 8.5% in the second quarter of 2006. The effect of hedges is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production taxes paid to taxing authorities.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $9.0 million from $19.0 million in the second quarter of 2005 to $28.0 in the second quarter of 2006 due to a higher per BOE rate and increased production volumes. The per BOE rate increased $2.41 from the second quarter of 2005 due to higher commodity prices along with increased rig rates and oilfield services costs, which have elevated finding, development, and acquisition costs. These factors resulted in additional DD&A expense of $6.8 million. The increase in production volumes of 289 MBOE over the second quarter of 2005 resulted in $2.2 million of additional DD&A expense.

Exploration expense. Exploration expense increased $0.2 million in the second quarter of 2006 as compared to the second quarter of 2005. During the second quarter of 2006, we expensed five exploratory dry holes with an average cost of approximately $0.4 million per well, compared to twelve exploratory dry holes expensed in the second quarter of 2005 with an average cost of approximately $0.2 million per well. In addition, impairment of unproved acreage increased $0.6 million from the second quarter of 2006 as we expanded our unproved acreage position and further defined our drilling success rates in certain areas. The following table details our exploration-related expenses for the second quarter of 2006 and 2005 (in thousands):

	Three months ended June 30,		***Increase /***
	2006	**2005**	***(Decrease)***
Exploration expenses:			
Dry hole	$ 1,998	$ 2,010	*$ (12)*
Geological and seismic	847	1,243	*(396)*
Delay rentals	129	108	*21*
Impairment of unproved acreage	1,042	411	*631*
Total	$ 4,016	$ 3,772	*$ 244*

General and administrative (G&A) expense. G&A expense increased $1.2 million from $4.2 million in the second quarter of 2005 to $5.4 million in the second quarter of 2006. The overall increase, as well as the $0.25 increase in the per BOE rate, is primarily the result of increased corporate staffing to manage our larger asset base, increased personnel costs due to intense competition for human resources within the industry, and increased stock-based compensation expense attributable to equity instruments granted to employees under our 2000 Incentive Stock Plan.

Prior to the adoption of SFAS 123R, non-cash stock-based compensation was separately reported on the statement of operations. All periods presented have been reclassified to allocate non-cash stock-based compensation to lease operations expense, G&A expense, and exploration expense. This change has resulted in additional G&A expense of $0.8 million in the second quarter of 2006, or $0.29 per BOE, as compared to $0.6 million in the second quarter of 2005, or $0.26 per BOE. The increase in non-cash stock-based compensation allocated to G&A expense is primarily due to new stock-based compensation awards granted to employees in 2006.

As of June 30, 2006, we had $13.4 million of total unrecognized compensation cost related to unvested, outstanding restricted stock. We expect to recognize this cost over a weighted average period of 3.3 years. Additionally, we had $2.5 million of total unrecognized compensation cost related to unvested stock options as of June 30, 2006. We expect to recognize this cost over a weighted average period of 2.0 years.

Derivative fair value loss. During the second quarter of 2006 we recorded a $10.8 million derivative fair value loss as compared to a $1.7 million loss recorded in the second quarter of 2005. This derivative fair value loss represents the ineffective portion of the mark-to-market (gain) loss on our derivative hedging instruments and mark-to-market (gains) losses related to commodity derivatives not designated as hedges.

The components of the derivative fair value (gain) loss reported in the second quarter of 2006 and 2005 are as follows (in thousands):

	Three months ended June 30, 2006	Three months ended June 30, 2005	*Increase / (Decrease)*
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$ (1,091)	$ 1,942	*$ (3,033)*
Undesignated derivative contracts:			
Mark-to-market (gain) loss:			
- Interest rate swap		(31)	*31*
- Commodity contracts	12,369		*12,369*
Settlements of commodity contracts	(484)	(219)	*(265)*
Total derivative fair value (gain) loss	$ 10,794	$ 1,692	*$ 9,102*

In the second quarter of 2006, we discontinued hedge accounting for certain contracts that were previously used to hedge oil production in the CCA and gas production in the North Louisiana Salt Basin. These contracts no longer qualified for hedge accounting as the expected cash flows from the derivative contracts were no longer expected to be highly effective at offsetting changes in cash flows from the hedged production using generally accepted parameters. As a result, our mark-to-market loss on derivative commodity contracts increased to $12.4 million for the second quarter of 2006. Ineffectiveness related to our derivative commodity contracts designated as hedges resulted in a $1.1 million gain due to decreasing natural gas wellhead to NYMEX price differentials and gains on our natural gas floor contracts.

In the third quarter of 2006, we anticipate that additional derivative contracts could no longer qualify for hedge accounting. To increase clarity in our financial statements by accounting for all contracts under the same method, we elected to discontinue hedge accounting prospectively for all of our remaining commodity derivatives beginning in July 2006. While this change will have no effect on our cash flows, future results of operations will be affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. We will recognize all prospective mark-to-market gains and losses in earnings rather than deferring such amounts in accumulated other comprehensive income included in stockholders equity.

Other operating expense. Other operating expense increased $0.3 million from $1.7 million in the second quarter of 2005 to $2.0 million in the second quarter of 2006. This increase is mainly due to an increase in third party natural gas transportation costs attributable to a higher cost environment and increased production volumes for the second quarter of 2006 over the same period in 2005.

Interest expense. Interest expense increased $3.3 million in the second quarter of 2006 as compared to the second quarter of 2005. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150.0 million of $7^1/4$% senior subordinated notes in November 2005 and $300.0 million of 6% senior subordinated notes in July 2005. We also redeemed $150.0 million of $8^3/8$% senior subordinated notes in August 2005. The weighted average interest rate, net of hedges, for the second quarter of 2006 was 7.1% as compared to 7.0% for the same period in 2005.

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The following table illustrates the components of interest expense for the three months ended June 30, 2006 and 2005 (in thousands):

	Three months ended June 30, 2006	2005	Increase / (Decrease)
$8^3/8$% senior subordinated notes due 2012	$	$ 3,234	*$ (3,234)*
$6^1/4$% senior subordinated notes due 2014	2,420	2,415	*5*
6% senior subordinated notes due 2015	4,620		*4,620*
$7^1/4$% senior subordinated notes due 2017	2,748		*2,748*
Revolving credit facility	488	1,708	*(1,220)*
Other	442	91	*351*
Total	$ 10,718	$ 7,448	*$ 3,270*

Income taxes. Income tax expense for the second quarter of 2006 increased $2.7 million over the same period in 2005. Our effective tax rate increased in the second quarter of 2006 to 40.3% from 34.3% in the second quarter of 2005 due to the absence of Section 43 income tax credits during the second quarter of 2006 and changes to the Texas franchise tax. The Enhanced Oil Recovery credits available under Section 43 are fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during the three months ended June 30, 2006. We were able to reduce our income tax provision in the second quarter of 2005 by $0.7 million from the generation of Section 43 credits. In addition, a Texas franchise tax reform measure was signed into law on May 18, 2006, which revised the computation of the Texas franchise tax to apply to numerous types of entities doing business in Texas that previously were not subject to the tax. We adjusted our net deferred tax balances using the new higher marginal tax rate we expect to be effective when those deferred taxes become current. This resulted in a charge of $1.3 million during the three months ended June 30, 2006.

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Results of Operations

Comparison of Six Months Ended June 30, 2006 to Six Months Ended June 30, 2005

Below is a comparison of our operations during the first six months of 2006 with the first six months of 2005.

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenues for the six months ended June 30, 2006 and 2005, as well as each period s respective oil and natural gas volumes (in thousands, except per unit and per day amounts):

	Six months ended June 30, 2006	Six months ended June 30, 2005	*Increase / (Decrease)*	
Revenues:				
Oil wellhead	$ 198,138	$ 156,898	*$ 41,240*	
Oil hedges	(25,324)	(20,203)	*(5,121)*	
Total Oil Revenues	$ 172,814	$ 136,695	*$ 36,119*	*26%*
Natural gas wellhead	$ 82,804	$ 58,124	*$ 24,680*	
Natural gas hedges	(5,931)	(3,521)	*(2,410)*	
Total Natural Gas Revenues	$ 76,873	$ 54,603	*$ 22,270*	*41%*
Combined wellhead	$ 280,942	$ 215,022	*$ 65,920*	
Combined hedges	(31,255)	(23,724)	*(7,531)*	
Total Combined Revenues	$ 249,687	$ 191,298	*$ 58,389*	*31%*
Revenues ($/Unit):				
Oil wellhead	$ 53.87	$ 46.11	*$ 7.76*	
Oil hedges	(6.89)	(5.94)	*(0.95)*	
Total Oil Revenues	$ 46.98	$ 40.17	*$ 6.81*	*17%*
Natural gas wellhead	$ 6.85	$ 6.20	*$ 0.65*	
Natural gas hedges	(0.49)	(0.38)	*(0.11)*	
Total Natural Gas Revenues	$ 6.36	$ 5.82	*$ 0.54*	*9%*
Combined wellhead	$ 49.36	$ 43.30	*$ 6.06*	
Combined hedges	(5.49)	(4.78)	*(0.71)*	

Total Combined Revenues	$ 43.87	$ 38.52	*$ 5.35*	*14%*
Total production volumes:				
Oil (Bbls)	3,678	3,403	*275*	*8%*
Natural gas (Mcf)	12,084	9,384	*2,700*	*29%*
Combined (BOE)	5,692	4,967	*725*	*15%*
Daily production volumes:				
Oil (Bbls/day)	20,319	18,799	*1,520*	*8%*
Natural gas (Mcf/day)	66,765	51,847	*14,918*	*29%*
Combined (BOE/day)	31,447	27,440	*4,007*	*15%*
Average NYMEX Prices:				
Oil (per Bbl)	$ 67.09	$ 51.51	*$ 15.58*	*30%*
Natural gas (per Mcf)	7.28	6.71	*0.57*	*8%*

Oil revenues increased $36.1 million from $136.7 million in the first six months of 2005 to $172.8 million in the first six months of 2006. The increase is due primarily to an increase in oil production volumes of 275 MBbls, which contributed approximately $12.7 million in additional revenues, and higher realized average oil prices, which contributed approximately $23.4 million in additional revenues. The increase in production volumes is the result of our development program and the integration of our 2005 acquisitions. The $23.4 million increase in revenues from higher realized average oil prices consists of a $28.5 million increase resulting from higher average wellhead oil prices, offset by increased hedging payments of $5.1 million, or $0.95 per Bbl. Our average wellhead oil price increased $7.76 per Bbl in the first six months of 2006 over the first six months of 2005 as a result of increases in the overall market price for oil as reflected in the increase in the average NYMEX price from $51.51 in the first six months of 2005 to $67.09 in the first six months of 2006. Please read the discussion below regarding the widening of our oil wellhead price to average NYMEX price differential and its related adverse impact on oil revenues for the first six months of 2006.

Our oil wellhead revenue was reduced by $12.2 million and $6.4 million in the first six months of 2006 and 2005, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $22.3 million from $54.6 million in the first six months of 2005 to $76.9 million in the first six months of 2006. The increase is due primarily to increased natural gas production volumes of 2,700 MMcf from our development program and the integration of our 2005 acquisitions, which contributed approximately $16.7 million in additional revenues, and higher realized average natural gas prices, which contributed approximately $5.6 million in additional revenues. The $5.6 million increase in revenues from higher realized average natural gas prices consists of an $8.0 million increase resulting from higher average wellhead natural gas prices, offset by increased hedging payments of $2.4 million, or $0.11 per Mcf. Our average wellhead natural gas price increased $0.65 per Mcf in the first six months of 2006 over the first six months of 2005 due to an increase in the overall market price of natural gas as reflected in the increase in the average NYMEX price from $6.71 in the first six months of 2005 to $7.28 in the first six months of 2006.

The table below illustrates the relationship between oil and natural gas wellhead prices as a percentage of the average NYMEX prices for the six months ended June 30, 2006 and 2005. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Six months ended June,	
	2006	**2005**
Oil wellhead ($/Bbl)	$ 53.87	$46.11
Average NYMEX ($/Bbl)	$ 67.09	$51.51
Differential to NYMEX	$(13.22)	$ (5.40)
Oil wellhead to NYMEX percentage	80%	90%
Natural gas wellhead ($/Mcf)	$ 6.85	$ 6.20
Average NYMEX ($/Mcf)	$ 7.28	$ 6.71
Differential to NYMEX	$ (0.43)	$ (0.51)
Natural gas wellhead to NYMEX percentage	94%	92%

As indicated above, our oil wellhead price as a percentage of the average NYMEX price decreased to 80% in the first six months of 2006 from 90% in the same period of 2005. The widening of the differential is due to market conditions in the Rocky Mountain refining area, which has adversely affected the wellhead price we received on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain area, created steep pricing discounts in the first quarter of 2006. These discounts narrowed in the second quarter of 2006, though they are still higher than our historical average. The decrease in the oil differential percentage in the first six months of 2006 as compared to the first six months of 2005 adversely impacted oil revenues by $28.7 million. As Rocky Mountain refiners have recently completed maintenance and increased their demand for crude oil, the differential narrowed from the first to the second quarter of 2006, but still remains wider than our historical average.

Our natural gas wellhead price as a percentage of the average NYMEX price increased to 94% in the first six months of 2006 from 92% in the same period of 2005. This favorable variance is due to our natural gas production in the North Louisiana Salt Basin and Crockett County, Texas, which is sold at Katy, Houston Ship Channel, and Henry Hub natural gas prices, which have recently been higher than the average front-month NYMEX natural gas price. The increase in the natural gas differential percentage favorably impacted natural gas revenues by $1.0 million in the first six months of 2006 as compared with the same period of 2005.

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Expenses. The following table summarizes our expenses for the six months ended June 30, 2006 and 2005:

	Six months ended June 30,		Increase / (Decrease)	
	2006	2005		
Expenses (in thousands):				
Production				
Lease operations	$ 45,854	$ 31,217	*$ 14,637*	
Production, ad valorem, and severance taxes	24,822	18,899	*5,923*	
Total production expenses	70,676	50,116	*20,560*	*41%*
Other				
Depletion, depreciation, and amortization	55,008	35,721	*19,287*	
Exploration	6,025	6,408	*(383)*	
General and administrative	11,949	8,332	*3,617*	
Derivative fair value loss	13,100	4,101	*8,999*	
Other operating	4,489	3,302	*1,187*	
Total operating	161,247	107,980	*53,267*	*49%*
Interest	22,505	14,407	*8,098*	
Current and deferred income tax provision	26,313	23,608	*2,705*	
Total expenses	$ 210,065	$ 145,995	$ 64,070	*44%*
Expenses (per BOE):				
Production				
Lease operations	$ 8.06	$ 6.29	*$ 1.77*	
Production, ad valorem, and severance taxes	4.36	3.81	*0.55*	
Total production expenses	12.42	10.10	*2.32*	*23%*
Other				
Depletion, depreciation, and amortization	9.66	7.19	*2.47*	
Exploration	1.06	1.29	*(0.23)*	
General and administrative	2.10	1.68	*0.42*	
Derivative fair value loss	2.30	0.83	*1.47*	
Other operating	0.79	0.66	*0.13*	
Total operating	28.33	21.75	*6.58*	*30%*
Interest	3.96	2.90	*1.06*	
Current and deferred income tax provision	4.62	4.75	*(0.13)*	
Total expenses	$ 36.91	$ 29.40	$ 7.51	*26%*

Production expenses (Lease operations and production, ad valorem, and severance taxes). Total production expenses increased $20.6 million from $50.1 million in the first six months of 2005 to $70.7 million in the first six months of 2006. This increase resulted from an increase in total production volumes, as well as a $2.32 increase in production expenses per BOE. Total production expenses per BOE increased by a larger percentage (23%) than total revenues per BOE (14%) due to increases in the differential between the oil wellhead price we receive and the average NYMEX price in the first six months of 2006. As a result of these changes, our production margin (defined as revenues less production expenses) for the first six months of 2006 increased 11% to $31.45 per BOE as compared to $28.42 per BOE for the first six months of 2005.

The production expense attributable to lease operations increased $14.7 million from $31.2 million in the first six months of 2005 to $45.9 million in the same period of 2006. The increase is due to higher production volumes, which contributed approximately $4.5 million of additional lease operations expense, and an increase in the average per BOE rate, which contributed approximately $10.1 million of additional lease operations expense. The increase in production volumes is the result of our development program and the integration of our 2005 acquisitions, which predominantly occurred in the second half of 2005. The increase in our average per BOE rate of $1.77 was attributable to increases in prices paid to oilfield service companies and suppliers due to a current higher price environment, increased operational activity to maximize production, the operation of higher operating cost wells (which have become more attractive due to increases in oil and natural gas prices) and increased stock-based compensation expense attributable to equity instruments granted to employees under our 2000 Incentive Stock Plan. Prior to the adoption of SFAS 123R, non-cash stock-based compensation was separately reported on the statement of operations. Due to the adoption of SFAS 123R, non-cash stock compensation in all prior periods presented has been reclassified to allocate the amount to the same respective income statement lines as the employees salary, cash bonus, and benefits. As all full-time employees, including field personnel, are eligible for equity grants under the Company s current incentive stock plan, lease operations expense, general and administrative expense, and exploration expense have been changed to reflect the new presentation. This change has resulted in additional lease operations expense of $1.0 million in the first six months of 2006, or $0.17 per BOE, as compared to $0.6 million in the first six months of 2005, or $0.13 per BOE. The increase in non-cash stock-based compensation allocated to lease operations expense is primarily due to new stock-based compensation awards granted to employees in 2006.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) for the six months ended June 30, 2006 increased as compared to the same period in 2005 by $5.9 million due to an increase in production volumes and an increase in the average wellhead price we received for oil and natural production. The increase in production volumes resulted in approximately $2.7 million of additional production taxes. The average wellhead price we received for oil and natural gas production increased $6.06 per BOE, resulting in additional production taxes of approximately $3.2 million in the first six months of 2006. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes remained consistent from the first six months of 2005 to the first six months of 2006 at 8.8% in each quarter. The effect of hedges is excluded from oil and natural gas revenues in the calculation of these percentages because this method more closely reflects the method used to calculate actual production taxes paid to taxing authorities.

Depletion, depreciation, and amortization (DD&A) expense. DD&A expense increased $19.3 million from $35.7 million in the first six months of 2005 to $55.0 million in the first six months of 2006 due to a higher per BOE rate and increased production volumes. The per BOE rate increased $2.47 from the first six months of 2005 due to higher commodity prices along with increased rig rates and oilfield services costs, which have elevated finding, development, and acquisition costs. These factors resulted in additional DD&A expense of $14.1 million. The increase in production volumes of 725 MBOE over the first six months of 2005 resulted in $5.2 million of additional DD&A expense.

Exploration expense. Exploration expense decreased $0.4 million in the first six months of 2006 as compared to the first six months of 2005. During the first six months of 2006, we expensed seven exploratory dry holes with an average cost of approximately $0.5 million per well, compared to seventeen exploratory dry holes expensed in the first six months of 2005 with an average cost of approximately $0.2 million. The following table details our exploration-related expenses for the first six months of 2006 and 2005 (in thousands):

	Six months ended June 30,		***Increase /***
	2006	**2005**	***(Decrease)***
Exploration expenses:			
Dry hole	$ 2,580	$ 3,329	*$ (749)*
Geological and seismic	1,252	1,721	*(469)*
Delay rentals	355	375	*(20)*
Impairment of unproved acreage	1,838	958	*880*
Total	$ 6,025	$ 6,383	*$ (358)*

General and administrative (G&A) expense. G&A expense increased $3.6 million from $8.3 million in the first six months of 2005 to $11.9 million in the first six months of 2006. The overall increase, as well as the $0.42 increase in the per BOE rate, is primarily the result of increased stock-based compensation expense attributable to equity instruments granted to employees under our 2000 Incentive Stock Plan.

Prior to the adoption of SFAS 123R, non-cash stock-based compensation was separately reported on the statement of operations. All periods presented have been reclassified to allocate non-cash stock-based compensation to lease operations expense, G&A expense, and exploration expense. This change has resulted in additional G&A expense of $3.9 million in the first six months of 2006, or $0.68 per BOE, as compared to $1.1 million in the first six months of 2005, or $0.23 per BOE. The increase in non-cash stock-based compensation allocated to G&A expense is primarily due to new stock-based compensation awards granted to employees in 2006. G&A expense related to non-cash stock-based compensation in the first six months of

2006 includes $2.1 million related to shares granted to retirement eligible employees. Restricted stock grants vest in full upon retirement, which results in non-cash stock-based compensation expense being fully recognized on the date of grant rather than over the vesting period for retirement eligible employees.

Derivative fair value loss. During the first six months of 2006, we recorded a $13.1 million derivative fair value loss as compared to a $4.1 million loss recorded in the first six months of 2005. This derivative fair value loss represents the ineffective portion of the mark-to-market (gain) loss on our derivative hedging instruments and mark-to-market (gains) losses related to commodity derivatives not designated as hedges.

The components of the derivative fair value (gain) loss reported in the first six months of 2006 and 2005 are as follows (in thousands):

	Six months ended June 30,		***Increase /***
	2006	**2005**	***(Decrease)***
Designated cash flow hedges:			
Ineffectiveness Derivative commodity contracts	$ 1,748	$ 4,667	*$ (2,919)*
Undesignated derivative contracts:			
Mark-to-market (gain) loss:			
Interest rate swap		150	*(150)*
Commodity contracts	12,369		*12,369*
Settlements of commodity contracts	(1,017)	(716)	*(301)*
Total derivative fair value (gain) loss	$ 13,100	$ 4,101	*$ 8,999*

In the second quarter of 2006, we discontinued hedge accounting for certain contracts that were previously used to hedge oil production in the CCA and gas production in the North Louisiana Salt Basin. These contracts no longer qualified for hedge accounting as the expected cash flows from the derivative contracts were no longer expected to be highly effective at offsetting changes in cash flows from the hedged production using generally accepted parameters. As a result, our mark-to-market loss on derivative commodity contracts increased to $12.4 million for the second quarter of 2006. Ineffectiveness related to our derivative commodity contracts decreased by $2.9 million due to decreasing natural gas wellhead to NYMEX price differentials and gains on our natural gas floor contracts.

Other operating expense. Other operating expense increased $1.2 million from $3.3 million in the first six months of 2005 to $4.5 million in the first six months of 2006. This increase is mainly due to an increase in third party natural gas transportation costs attributable to a higher cost environment and increased production volumes for the first six months of 2006 over the same period in 2005.

Interest expense. Interest expense increased $8.1 million in the first six months of 2006 as compared to the first six months of 2005. The increase is primarily due to additional debt used to finance acquisitions and our capital program. We issued $150.0 million of 7$^{1}/4$% senior subordinated notes in November 2005 and $300.0 million of 6% senior subordinated notes in July 2005. We also redeemed $150.0 million of 8?% senior subordinated notes in August 2005. The weighted average interest rate, net of hedges, for the first six months of 2006 was 7.1% as compared to 7.0% for the same period in 2005.

The following table illustrates the components of interest expense for the six months ended June 30, 2006 and 2005 (in thousands):

	Six months ended June 30,		***Increase /***
	2006	**2005**	***(Decrease)***
8$^{3}/8$% senior subordinated notes due 2012	$	$ 6,460	*$ (6,460)*
6$^{1}/4$% senior subordinated notes due 2014	4,840	4,822	*18*
6% senior subordinated notes due 2015	9,171		*9,171*

$7^{1}/4\%$ senior subordinated notes due 2017	5,493		*5,493*
Revolving credit facility	2,223	2,903	*(680)*
Other	778	222	*556*
Total	$ 22,505	$ 14,407	*$ 8,098*

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Income taxes. Income tax expense for the first six months of 2006 increased $2.7 million over the same period in 2005. Our effective tax rate increased in the first six months of 2006 to 39.6% from 34.2% in the first six months of 2005 due to the absence of Section 43 income tax credits during the first six months of 2006 and changes to the Texas franchise tax. The Enhanced Oil Recovery credits available under Section 43 are fully phased out for the 2006 tax year due to high oil prices in 2005. Therefore, no credits were generated during the three months ended June 30, 2006. We were able to reduce our income tax provision in the first six months of 2005 by $1.4 million from the generation of Section 43 credits. In addition, a Texas franchise tax reform measure was signed into law on May 18, 2006, which revised the computation of the Texas franchise tax to apply to numerous types of entities doing business in Texas that previously were not subject to the tax. We adjusted our net deferred tax balances using the new higher marginal tax rate we expect to be effective when those deferred taxes become current. This resulted in a charge of $1.3 million during the six months ended June 30, 2006.

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Capital Resources

Our primary capital resources are as follows:

- Cash flows from operating activities
- Cash flows from financing activities
- Current capitalization

Cash flows from operating activities. Cash provided by operating activities increased $14.0 million from $117.5 million for the six months ended June 30, 2005 to $131.5 million for the six months ended June 30, 2006. Although total revenues in the first six months of 2006 increased $58.4 million (31%) from the first six months of 2005, a widening in the differential between the wellhead price we received for our CCA and Williston Basin oil production and the average NYMEX price for oil in the first six months of 2006 caused total revenues per BOE in the first quarter of 2006 to increase only 14% from the first six months of 2005. The increase in revenues per BOE was largely offset by a 30% increase in total operating expenses per BOE, which resulted in a smaller increase in cash provided by operating activities. Total operating expenses increased $53.2 million from $108.0 million for the first six months of 2005 to $161.2 million for the first six months of 2006.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt and proceeds received from the issuance of our common stock in April 2006. During the first six months of 2006, we received net cash of $33.9 million from financing activities.

On April 4, 2006, we received net proceeds of approximately $126.9 million from a public offering of 4.0 million shares of our common stock. The net proceeds were used to repay outstanding balances under our revolving credit facility, invest in oil and natural gas activities, and to pay general corporate expenses.

We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments. During the first six months of 2006, using funds we received from our equity issuance, we repaid the balance of $80.0 million outstanding at December 31, 2005. As a result, we had no amounts outstanding at June 30, 2006.

During the first six months of 2005, we received net cash of $48.6 million from financing activities. This consisted primarily of a net increase in amounts outstanding under our revolving credit facility of $61.0 million used to fund increased investments for the development of oil and natural gas properties, offset by an increase in our cash overdrafts.

Current capitalization. At June 30, 2006, we had total assets of $1.8 billion. Total capitalization as of June 30, 2006 was $1.3 billion, of which 56% was represented by stockholders equity and 44% by long-term debt. At December 31, 2005, we had total assets of $1.7 billion. Total capitalization as of December 31, 2005 was $1.2 billion, of which 45% was represented by stockholders equity and 55% by long-term debt. The percentages of our capitalization represented by stockholders equity and long-term debt could vary in the future if debt or equity is used to finance future capital projects or potential acquisitions.

Capital Commitments

Our primary needs for cash are as follows:

- Development, exploitation, and exploration of our existing oil and natural gas properties
- Acquisitions of oil and natural gas properties and leasehold acreage costs
- Other general property and equipment
- Funding of necessary working capital
- Payment of contractual obligations

Development, exploitation, and exploration of existing properties. The following table summarizes our costs incurred

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(excluding asset retirement obligations) related to development, exploitation, and exploration activities during the three and six months ended June 30, 2006 and 2005 (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2006	2005	2006	2005
Development and exploitation	$ 63,010	$ 57,979	$ 95,895	$ 100,884
Exploration	16,909	13,706	38,633	28,403
HPAI	7,878	9,299	14,459	17,241
Total	$ 87,797	$ 80,984	$ 148,987	$ 146,528

Development and exploitation. Our expenditures for development and exploitation investments primarily relate to drilling development and infill wells, workovers of existing wells, and field related facilities (excluding development-related asset retirement obligations). Our development and exploitation capital for the three months ended June 30, 2006 included a total of 46 gross (19.3 net) successful wells and no development dry holes. Our development and exploitation capital for the first half of 2006 included a total of 90 gross (38.4 net) successful wells and no development dry holes.

We operated between eight and ten drilling rigs during the second quarter of 2006, including three rigs related to our West Texas joint development agreement. Higher working interests and generally elevated service costs have required additional capital for a given well in our 2006 drilling program. As a result of these factors, our capital expenditures outpaced operating cash flow in the second quarter of 2006. In order to attain a better balance between investment and cash flow, we have opted to release a limited number of rigs, and instead plan to drill fewer yet higher-quality prospects during the remainder of 2006. Production attributable to some of these higher-quality prospects will not have an appreciable effect on results of operations for fiscal 2006, since such wells typically take several months to bring online.

Exploration. Our expenditures for exploration investments primarily relate to drilling exploratory wells, seismic costs, delay rentals, and geological and geophysical costs. During the three months ended June 30, 2006, our exploration capital was invested primarily in drilling extension and exploratory wells in the Mid-Continent area. In the second quarter of 2006, our exploration capital yielded 12 gross (1.6 net) exploratory wells that were productive and 5 gross (3.6 net) exploratory dry holes. During the six months ended June 30, 2006, our exploration capital yielded 24 gross (7.1 net) exploratory wells that were productive and 7 gross (4.7 net) exploratory dry holes.

High-pressure air injection programs. In the Little Beaver area, our HPAI project continues to keep production stable without drilling additional wells. Implementation of HPAI in Little Beaver Phases I and II was completed in the fourth quarter of 2004.

In the Pennel and Coral Creek areas of the CCA, we completed Phases I and II of the HPAI project in the fourth quarter of 2005, and we are seeing initial indications of response and expect to see more meaningful response toward the end of 2006. Implementation of Phase III at Pennel is currently underway.

Acquisitions and leasehold acreage costs. The following table summarizes our costs incurred (excluding asset retirement obligations) for oil and natural gas property acquisitions during the three and six months ended June 30, 2006 and 2005 (in thousands):

	Three months ended June 30,		Six months ended June 30,	
	2006	2005	2006	2005
Acquisitions of proved properties	$ 3,545	$ 4,986	$ 4,052	$ 10,657
Leasehold acreage costs	4,683	3,039	11,865	6,722
Total	$ 8,228	$ 8,025	$ 15,917	$ 17,379

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Acquisitions. Our capital expenditures for proved oil and natural gas properties during the three months ended June 30, 2006 totaled $3.5 million as compared to $5.0 million in the same period in 2005. The $3.5 million of acquisition capital in the second quarter of 2006 was invested primarily in additional working interests in the Permian Basin, while the $5.0 million in the second quarter of 2005 was invested primarily in additional working interests in the Mid-Continent region. We do not budget for acquisitions. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio.

Leasehold acreage costs. Our capital expenditures for leasehold acreage costs during the three months ended June 30, 2006 and 2005 totaled $4.7 million and $3.0 million, respectively. Undeveloped leasehold costs incurred in each period consists of costs for acreage spread over our various core areas.

***Other general property and equipment*.** Our capital expenditures for other general property and equipment during the three months ended June 30, 2006 and 2005 totaled $1.5 million and $2.0 million, respectively. The decrease was due primarily to higher levels of field equipment purchased in 2005 in anticipation of our expected increased development activities. Capital expenditures for other general property and equipment include corporate leasehold improvements, computers, and various field equipment.

Funding of necessary working capital. At June 30, 2006, our working capital (defined as total current assets less total current liabilities) was negative $28.4 million while at December 31, 2005, our working capital was negative $56.8 million, an increase of $28.4 million. The increase is primarily attributable to proceeds received from our public issuance of 4.0 million shares of common stock which allowed us to pay down current liabilities and changes in the fair value of outstanding derivative contracts, net of the deferred tax effect of marking these contracts to market.

For the remainder of 2006, we expect working capital to remain negative. Negative working capital is expected mainly due to fair values of our derivative contracts, the settlements of which will be offset by cash flows from hedged production. We anticipate future cash reserves to be close to zero as we plan to use available cash to fund capital obligations and pay general corporate expenses. We do not plan to pay cash dividends in the foreseeable future. The overall 2006 market prices for oil and natural gas along with the impact of differentials between those market prices and the wellhead prices we receive on our production will be the largest variables driving the different components of working capital.

Higher working interests and generally elevated service costs have required additional capital for a given well in our 2006 drilling program. As a result of these factors, we increased oil and natural gas related budgeted capital expenditures from $320.0 million to approximately $350.0 million. The level of these and other future expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly, depending on available opportunities, timing of projects, and market conditions. We plan to finance our ongoing expenditures using internally generated cash flow, cash on hand, and our revolving credit facility.

Contractual obligations. The following table illustrates our contractual obligations and commercial commitments outstanding at June 30, 2006 (in thousands):

Contractual Obligations	**Payments Due by Period**				
and Commitments	**Total**	**2006**	**2007 - 2008**	**2009 - 2010**	**Thereafter**
$6^1/4$% notes (a)	$ 224,987	$ 4,687	$ 18,750	$ 18,750	$ 182,800
6% notes (a)	471,000	9,000	36,000	36,000	390,000
$7^1/4$% notes (a)	275,063	5,438	21,750	21,750	226,125
Revolving credit facility					
Derivative obligations (b)	115,123	34,161	80,962		
Development commitments (c)	194,550	66,513	109,502	18,535	
Operating leases (d)	11,174	914	3,198	2,950	4,112
Asset retirement obligations (e)	125,140	616	1,234	1,234	122,056
Total	$ 1,417,037	$ 121,329	$ 271,396	$ 99,219	$ 925,093

(a) Amounts included in the table above include both principal and projected interest payments.

(b) Derivative obligations represent liabilities for derivatives that were valued as of June 30, 2006. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk.

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(c) Development commitments represent authorized purchases, $31.8 million of which represents work in process and is accrued at June 30, 2006. At June 30, 2006, we had $111.9 million of authorized purchases not placed to vendors (authorized AFEs) which were not accrued, but are budgeted for and expected to be made during 2006 unless circumstances change. Development commitments in the above table also include future minimum payments for electricity, seismic data analysis, and drilling rig operations.

(d) Operating leases represent office space and equipment obligations that have remaining non-cancelable lease terms in excess of one year.

(e) Asset retirement obligations represent the undiscounted future plugging and abandonment expenses on oil and natural gas properties and related facilities disposal at the completion of field life.

Liquidity

Cash on hand, internally generated cash flows and the borrowing capacity under our revolving credit facility are our major sources of liquidity. We also have the ability to adjust our level of capital expenditures. We may use other sources of capital, including the issuance of additional debt or equity securities, to fund any major acquisitions we might secure in the future and to maintain our financial flexibility.

Internally generated cash flows. Our internally generated cash flows, results of operations and financing for our operations are dependent on oil and natural gas prices. Realized oil and natural gas prices for the first six months of 2006 were 14% higher as compared to the first six months of 2005. These prices have historically fluctuated widely in response to changing market forces. For the first six months of 2006, approximately 65% of our production was oil. As we previously discussed, our oil wellhead differentials during the first six months of 2006 increased significantly from the same period in 2006, adversely impacting the amount of revenues we received on our oil production. To the extent oil and natural gas prices decline or we continue to experience significantly increased wellhead differentials, our earnings, cash flows from operations, and availability under our revolving credit facility may be adversely impacted. Prolonged periods of low oil and natural gas prices or sustained wider than historical wellhead differentials could cause us to not be in compliance with maintenance covenants under our revolving credit facility and thereby affect our liquidity. We believe that our cash flows and unused availability under our revolving credit facility are sufficient to fund our planned capital expenditures for the foreseeable future.

Revolving credit facility. Our principal source of short-term liquidity is our revolving credit facility. The revolving credit facility is with a bank syndicate comprised of Bank of America, N.A. and other lenders. The borrowing base is determined semi-annually and may be increased or decreased, up to a maximum of $750.0 million. The borrowing base as of June 30, 2006 was $550.0 million. The revolving credit facility matures on December 29, 2010.

On June 30, 2006, we had no amounts outstanding and $495.0 million available to borrow under the revolving credit facility. On August 3, 2006, we had no amounts outstanding and $492.2 million available to borrow under the credit facility.

Letters of credit. As of June 30, 2006, we had $55.0 million in letters of credit posted primarily with two of our commodity derivative contract counterparties. At any point in time, we have hedge margin deposits and letters of credit equal to the amount by which the current mark-to-market liability of our commodity derivative contracts exceeds the margin maintenance thresholds we have negotiated with our counterparties. Once a margin threshold is reached, we are required to maintain cash reserves in an account with the counterparty or post letters of credit in lieu of cash to ensure future settlement is made pursuant to our contracts. These funds are released back to us as our mark-to-market liability decreases due to either a drop in the futures price of oil and natural gas or due to the passage of time as settlements are made. Although we did not have any margin deposits with our counterparties as of June 30, 2006, if commodity prices were to rise substantially, we would be required to post margin reserves with one or more counterparties to secure future hedging settlements. As of August 3, 2006, we had $57.8 million of outstanding letters of credit posted in lieu of cash margin deposits.

Contingencies

In order to facilitate ongoing sales of our oil production in the CCA, we ship a portion of our production in pipelines downstream and sell to purchasers at major U.S. market hubs. From time to time, shipping delays, purchaser stipulations, or other conditions may require that we sell our oil production in periods subsequent to the period in which it is produced. In such case, the deferred sale would have an adverse effect in the period of production on reported production volumes, revenues, and costs as measured on a unit-of-production basis.

The sale of our CCA oil production is dependent on transportation through Butte Pipeline to markets in the Guernsey,

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Wyoming area. To a lesser extent, our production also depends on transportation through Platte Pipeline to Wood River, Illinois as well as other pipelines connected to the Guernsey, Wyoming area. While shipments on Platte Pipeline are currently oversubscribed and have been subject to apportionment since December 2005, we have been able to move our produced volumes through Platte Pipeline. In addition, shipments on Butte Pipeline were also apportioned in April 2006, but we have continued to move our produced volumes from the CCA to market. However, further restrictions on the available capacity to transport oil through these pipelines could have a material adverse effect on price received, production volumes, and revenues.

Our oil wellhead price as a percentage of the average NYMEX price decreased to 80% in the first six months of 2006 from 90% in the same period of 2005. The widening of the differential is due to market conditions in the Rocky Mountain area, which has adversely affected the wellhead price we received on our CCA and Williston Basin production. Production increases from competing Canadian and Rocky Mountain producers, in conjunction with limited refining and pipeline capacity in the Rocky Mountain refining area during the first quarter of 2006, created deep pricing discounts. As Rocky Mountain refiners have completed maintenance and increased their demand for crude oil, the differential has narrowed from the first quarter 2006 level of 77%. However, future differentials are expected to remain wider than our historical average.

Critical Accounting Policies and Estimates

On January 1, 2006, we adopted the provisions of SFAS No. 123R, *Share-Based Payment*. SFAS No. 123R is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*, and supersedes APB No. 25, *Accounting for Stock Issued to Employees*. SFAS No. 123R eliminates the option of using the intrinsic value method of accounting previously available, and requires companies to recognize in the financial statements the cost of employee services received in exchange for awards of equity instruments based on the grant date fair value of those awards. See Note 11 to our unaudited financial statements included elsewhere in this Form 10-Q for more information. There have been no other material changes to our critical accounting estimates since December 31, 2005.

During July 2006, we elected to discontinue hedge accounting prospectively for all of our commodity derivatives which were previously accounted for as hedges. While this change will have no effect on our cash flows, future results of operations will be affected by mark-to-market gains and losses, which fluctuate with the swings in oil and natural gas prices. As of July 2006, all remaining derivative contracts accounted for as hedges in the second quarter of 2006 were dedesignated. At this point, the gain (loss) to be amortized to revenue is established and deferred in accumulated other comprehensive income included in stockholders equity. We will recognize all prospective mark-to-market gains and losses in earnings rather than deferring such amounts in accumulated other comprehensive income.

Please read Management s Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates in Encore s 2005 Annual Report on Form 10-K for more information.

New Accounting Pronouncements

The effects of new accounting pronouncements are discussed in Note 2 to our unaudited consolidated financial statements included elsewhere in this Form 10-Q.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The information included in Quantitative and Qualitative Disclosures about Market Risk in Encore s 2005 Annual Report on Form 10-K is incorporated herein by reference. Such information includes a description of Encore s potential exposure to market risks, including commodity price risk and interest rate risk. The Company s outstanding derivative contracts as of June 30, 2006 are discussed in Note 5 to the accompanying consolidated financial statements. As of June 30, 2006, the fair value of our open commodity derivative contracts was a liability of $71.9 million. Based on our open commodity derivative positions at June 30, 2006, a $1.00 increase in the NYMEX prices for oil and natural gas would result in an increase to our derivative fair value liability of approximately $12.9 million, while a $1.00 decrease in the NYMEX prices for oil and natural gas would result in a decrease in our derivative fair value liability of approximately $14.6 million.

At June 30, 2006, we had total long-term debt of $593.4 million, which is recorded net of discount of $6.6 million. Of this amount, $150.0 million bears interest at a fixed rate of $6^1/4$%, $300.0 million bears interest at a fixed rate of 6%, and $150.0 million bears interest at a fixed rate of $7^1/4$%. At June 30, 2006, we had no amounts outstanding under our revolving credit

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facility, which is subject to floating market rates of interest that are linked to LIBOR.

Item 4. Controls and Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, we carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of June 30, 2006 to provide reasonable assurance that information required to be disclosed in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

There has been no change in our internal control over financial reporting that occurred during the three months ended June 30, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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PART II. OTHER INFORMATION

Item 1A. Risk Factors

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2005, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing our company. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or future results.

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

The following table summarizes purchases of our common stock during the three months ended June 30, 2006:

Month	Total Number of Shares Purchased	Average Price Paid per Share	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
April		$		
May		$		
June (a)	6,553	$ 26.83		
Total	6,553	$ 26.83		

(a) During the three months ended June 30, 2006, we purchased shares of common stock as treasury shares to pay income tax withholding obligations in conjunction with vesting of restricted shares under our 2000 Incentive Stock Plan.

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

The Company s annual meeting of stockholders was held Tuesday, May 2, 2006. The items submitted to stockholders for vote were the election of eight nominees to serve on the Company s Board of Directors during 2006 and until the Company s next annual meeting and to ratify the appointment of the independent registered public accounting firm for 2006. Notice of the meeting and proxy information was distributed to stockholders prior to the meeting in accordance with law. There were no solicitations in opposition to the nominees. Out of a total of 49,768,854 shares of the Company s common stock outstanding and entitled to vote, 46,478,263 shares (93.4%) were present at the meeting in person or by proxy.

Election of Directors

There were eight nominees for election as directors of the Company. The vote tabulation with respect to each nominee to the Company s Board of Directors was as follows:

NOMINEE	FOR	WITHHELD
I. Jon Brumley	45,933,000	545,263
Jon S. Brumley	46,278,617	199,646
John A. Bailey	46,242,238	236,025
Martin C. Bowen	46,250,685	227,578
Ted Collins, Jr.	45,979,018	499,245
Ted A. Gardner	46,279,063	199,200
John V. Genova	46,273,085	205,178
James A. Winne III	46,240,821	237,442

Appointment of Independent Registered Public Accounting Firm

The Board of Directors recommended that the Company s stockholders ratify the appointment of Ernst & Young LLP as the Company s independent registered public accounting firm. The vote tabulation with respect to the ratification of the appointment of the independent registered public accounting firm was as follows:

FOR	AGAINST	ABSTAIN
46,295,810	161,027	21,426

Item 6. Exhibits

Exhibits

3.1 Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).

3.1.2 Certificate of Amendment to Second Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2005, filed with the SEC on May 5, 2005).

3.2 Second Amended and Restated Bylaws of the Company (incorporated by reference to the Company s Quarterly Report on Form 10-Q for the fiscal quarter ended September 30, 2001, filed with the SEC on November 7, 2001).

+10.1 Table of Base Salaries for Named Executive Officers of the Company.

12.1 Statement showing computation of ratios of earnings to fixed charges.

31.1 Rule 13a-14(a)/15d-14(a) Certification (Principal Executive Officer)

31.2 Rule 13a-14(a)/15d-14(a) Certification (Principal Financial Officer)

32.1 Section 1350 Certification (Principal Executive Officer)

32.2 Section 1350 Certification (Principal Financial Officer)

\+ Management contract or compensatory plan, contract or arrangement.

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SIGNATURES

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

Date: August 7, 2006

By: /s/ Robert C. Reeves

Robert C. Reeves
Senior Vice President, Chief Accounting Officer and Controller