ENCORE ACQUISITION CO
Form 10-Q
May 09, 2006

Table of Contents

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 March 31, 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 May 3, 2006 52,795,955

ENCORE ACQUISITION COMPANY
INDEX

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain information included in this Quarterly Report on Form 10-Q and other materials filed with the SEC, 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, believe, should, forecast 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 Securities and Exchange Commission. 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.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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

	March 31, 2006	December 31, 2005
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,151	$ 1,654
Accounts receivable	60,085	76,960
Inventory	18,480	11,231
Derivatives	7,057	8,826
Deferred taxes	25,623	29,030
Other	4,834	5,656
Total current assets	117,230	133,357
Properties and equipment, at cost successful efforts method:		
Proved properties	1,751,742	1,691,175
Unproved properties	44,004	37,646
Accumulated depletion, depreciation, and amortization	(282,339)	(255,564)
	1,513,407	1,473,257
Other property and equipment	16,333	15,894
Accumulated depreciation	(5,926)	(5,366)
	10,407	10,528
Goodwill	59,201	59,046
Derivatives	9,372	17,316
Other	13,798	12,201
Total assets	$ 1,723,415	$ 1,705,705
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 20,327	$ 27,281
Accrued and other current	67,229	86,399
Derivatives	59,549	68,850
Deferred premiums on derivative contracts	10,815	7,665

Total current liabilities	157,920	190,195
Derivatives	36,705	44,087
Future abandonment cost	14,193	14,430
Deferred taxes	225,689	213,268
Long-term debt	692,314	673,189
Deferred premiums on derivative contracts	18,030	22,476
Other	1,250	1,279
Total liabilities	1,146,101	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, 48,795,955 and 48,784,846 issued and outstanding, respectively	488	488
Additional paid-in capital	320,841	316,619
Treasury stock, at cost, of 0 and 11,169 shares, respectively		(375)
Retained earnings	320,575	302,875
Accumulated other comprehensive income	(64,590)	(72,826)
Total stockholders equity	577,314	546,781
Total liabilities and stockholders equity	$ 1,723,415	$ 1,705,705

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

1

Table of Contents

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

	Three months ended March 31,	
	2006	**2005**
Revenues:		
Oil	$ 78,686	$ 67,136
Natural gas	37,530	24,445
Total revenues	116,216	91,581
Expenses:		
Production -		
Lease operations	22,736	15,149
Production, ad valorem, and severance taxes	12,242	9,086
Depletion, depreciation, and amortization	27,020	16,683
Exploration	2,009	2,623
General and administrative	6,528	4,115
Derivative fair value loss	2,306	2,409
Other operating	2,529	1,599
Total expenses	75,370	51,664
Operating income	40,846	39,917
Other income (expenses):		
Interest	(11,787)	(6,959)
Other	121	64
Total other income (expenses)	(11,666)	(6,895)
Income before income taxes	29,180	33,022
Current income tax provision	(282)	(801)
Deferred income tax provision	(10,962)	(10,437)
Net income	$ 17,936	$ 21,784
Net income per common share:		
Basic	$ 0.37	$ 0.45
Diluted	0.36	0.44

Weighted average common shares outstanding:		
Basic	48,797	48,614
Diluted	49,772	49,400

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

Table of Contents

ENCORE ACQUISITION COMPANY
CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY
March 31, 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	22		503					503
Cancellation of treasury stock	(11)		(139)	11	375	(236)		
Non-cash stock based compensation			3,858					3,858
Components of comprehensive income:								
Net income						17,936		17,936
Change in deferred hedge gain/loss (Net of income taxes of $4,906)							8,236	8,236
Total comprehensive income								26,172
Balance at March 31, 2006	48,796	$ 488	$ 320,841		$	$ 320,575	$ (64,590)	$ 577,314

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

Table of Contents

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

	Three months ended March 31, 2006	2005
Operating activities		
Net income	$ 17,936	$ 21,784
Adjustments to reconcile net income to net cash provided by operating activities:		
Depletion, depreciation, and amortization	27,020	16,683
Dry hole expense	534	1,319
Deferred taxes	10,962	10,437
Non-cash stock based compensation	3,653	773
Non-cash derivative loss	6,099	4,644
Other non-cash	1,204	965
Loss on disposition of assets	387	149
Changes in operating assets and liabilities:		
Accounts receivable	16,907	(7,008)
Other current assets	(6,136)	(1,659)
Other assets	(96)	(3,693)
Accounts payable and other current liabilities	(23,803)	10,457
Cash provided by operating activities	54,667	54,851
Investing Activities		
Purchases of other property and equipment	(1,058)	(2,729)
Acquisition of oil and natural gas properties	(7,689)	(9,354)
Development of oil and natural gas properties	(60,368)	(64,799)
Other	(1,352)	214
Cash used by investing activities	(70,467)	(76,668)
Financing Activities		
Exercise of stock options and other	303	1,013
Proceeds from long-term debt	94,000	71,000
Payments on long-term debt	(75,000)	(40,000)
Cash overdrafts	(4,006)	(10,288)
Cash provided by financing activities	15,297	21,725
Decrease in cash and cash equivalents	(503)	(92)
Cash and cash equivalents, beginning of period	1,654	1,103
Cash and cash equivalents, end of period	$ 1,151	$ 1,011

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

ENCORE ACQUISITION COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
March 31, 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 March 31, 2006, and the results of operations and cash flows for the three months ended March 31, 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.

Presentation of Number of Shares of Common Stock and Per Share Information

On June 15, 2005, the Company announced that its Board of Directors approved a three-for-two split of the Company s outstanding common stock in the form of a stock dividend. The dividend was distributed on July 12, 2005, to stockholders of record at the close of business on June 27, 2005. All share and per-share information included in the accompanying consolidated financial statements and related notes thereto for all periods presented have been adjusted retroactively to reflect the stock split.

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 10. Incentive Stock Plan for more information.

New Accounting Standards

FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations

In March 2005, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations*. The interpretation clarifies the requirement to record abandonment liabilities stemming from legal obligations when the retirement depends on a conditional future event. FIN No. 47 requires that the uncertainty about the timing or method of settlement of a conditional retirement obligation be factored into the measurement of the liability when sufficient information exists. FIN No. 47 became effective for the Company beginning January 1, 2006 and has not had a material impact on the Company s financial condition, results of operations, or cash flows.

Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3

In May 2005, the FASB issued SFAS No. 154, *Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3* . SFAS No. 154 requires retrospective application to prior period financial statements for changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. SFAS No. 154 also requires that retrospective application of a change in accounting principle be limited to the direct effects of the change. Indirect effects of a change in accounting principle should be recognized in the period of the accounting change. SFAS No. 154 became effective for the Company beginning January 1, 2006. SFAS No. 154 has not had a material impact on the Company s financial condition, results of operations, or cash flows.

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 Company does not expect Issue No. 04-13 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):

	March 31, 2006	December 31, 2005
Warehouse inventory	$ 9,542	$ 9,019
Oil in pipelines	8,938	2,212
Total	$ 18,480	$ 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 $109.7 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 $0.8 million.

Table of Contents

The calculation of the total purchase price and the estimated allocation as of March 31, 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	813
Total purchase price	$ 109,687

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

Cash	$ 18,592
Current assets, excluding cash	3,162
Proved oil and gas properties	85,388
Unproved oil and gas properties	6,863
Goodwill	21,293
Total assets acquired	135,298
Current liabilities	(8,689)
Non-current liabilities	(1,190)
Deferred income taxes	(15,732)
Total liabilities assumed	(25,611)
Fair value of net assets acquired	$ 109,687

The purchase price allocation resulted in $21.3 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 $15.7 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

The following tables summarize the Company s open commodity derivative instruments designated as hedges as of March 31, 2006:

Oil Derivative Instruments at March 31, 2006

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)
April June 2006	13,500	$44.07	1,000	$29.88	3,000	$37.27	$(11,712)

July Dec. 2006	13,000	45.00	1,000	29.88	3,000	37.27	(23,400)
Jan. Dec. 2007	8,000	53.75	-	-	3,000	36.75	(26,886)
Jan. June 2008	-	-	-	-	1,000	58.59	(1,662)

Natural Gas Derivative Instruments at March 31, 2006

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)
April Dec. 2006	32,500	$6.17	5,000	$5.68	12,500	$5.08	$ (8,732)
Jan. Dec. 2007	22,500	6.96	-	-	10,000	4.99	(8,758)

As a result of hedging transactions for oil and natural gas, the Company recognized a pre-tax reduction in revenues of approximately $16.5 million and $10.8 million in the three months ended March 31, 2006 and 2005, respectively. The Company also recognizes in its Consolidated Statements of Operations: (1) derivative fair value gains and losses related to changes in the

Table of Contents

market value of basis swaps and certain other commodity derivatives that are not designated for hedge accounting; and (2) ineffectiveness of commodity futures contracts designated as hedges.

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 March 31, 2006, the mark-to-market value of these basis swap contracts was a $1.3 million asset.

The actual gains or losses the Company realizes from derivative transactions may vary significantly from the deferred loss amount recorded in stockholders equity at March 31, 2006 due to the fluctuation of prices in the commodities markets.

The Company had $28.8 million of derivative premiums payable recorded at March 31, 2006, of which $18.0 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 April 2006 to December 2007.

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 March 31, 2006 (in thousands):

	Three months ended March 31, 2006
Future abandonment liability at January 1, 2006	$ 14,430
Wells drilled	38
Accretion expense	167
Plugging and abandonment costs incurred	(442)
Future abandonment liability at March 31, 2006	$ 14,193

7. Debt

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

	March 31, 2006	December 31, 2005
Revolving credit facility	$ 99,000	$ 80,000
$6^1/4$% Notes	150,000	150,000
6% Notes, net of unamortized discount of $5,213 and $5,317, respectively	294,787	294,683
$7^1/4$% Notes, net of unamortized discount of $1,473 and $1,494, respectively	148,527	148,506
Total	$ 692,314	$ 673,189

The Company had $40.0 million of outstanding letters of credit at March 31, 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 $411.0 million at March 31, 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

Table of Contents

amounts outstanding under our revolving credit facility and to pay general corporate expenses. See Note 14. Subsequent Event for more information.

8. Income Taxes

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

	Three months ended March 31, 2006	Three months ended March 31, 2005
Income before income taxes	$ 29,180	$ 33,022
Tax at statutory rate	$ 10,213	$ 11,558
State income taxes, net of federal benefit	781	693
Section 43 credits		(778)
Permanent and other	250	(235)
Income tax provision	$ 11,244	$ 11,238

9. Earnings Per Share (EPS)

The following table sets forth basic and diluted EPS computations for the three months ended March 31, 2006 and 2005 (in thousands, except per share data):

	Three months ended March 31, 2006	Three months ended March 31, 2005
Numerator:		
Net income	$ 17,936	$ 21,784
Denominator:		
Denominator for basic earnings per share -		
Weighted average shares outstanding	48,797	48,614
Effect of dilutive options and diluted restricted stock (a)	975	786
Denominator for diluted earnings per share	49,772	49,400
Net income per common share:		
Basic	$ 0.37	$ 0.45
Diluted	$ 0.36	$ 0.44

(a) There were no shares of antidilutive outstanding employee stock options or restricted stock for the three months ended

March 31, 2006. For the three months ended March 31, 2005, there were 113,036 employee stock options and 155,190 shares of restricted stock that were excluded from the calculation of diluted earnings per share because their effect would have been antidilutive.

10. 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 March 31, 2006, there were 1,219,296 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.

Table of Contents

All options that have been granted under the Plan have a strike price equal to the market price on the date of grant. 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.

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

The following table shows net income and basic and diluted net income per common share as reported, as well as pro forma amounts as if the Company had adopted SFAS No. 123R prior to January 1, 2006 (in thousands, except per common share amounts):

	Three Months Ended March 31, 2005
As Reported:	
Non-cash stock based compensation (net of taxes)	$ 484
Net income	21,784
Basic net income per share	0.45
Diluted net income per share	0.44
Pro Forma:	
Non-cash stock based compensation (net of taxes)	$ 647
Net income	21,621
Basic net income per share	0.44
Diluted net income per share	0.44

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 three months ended March 31, 2006 was $3.7 million and $1.3 million, respectively. During the

10

three months ended March 31, 2006, the Company also capitalized $0.2 million of compensation cost as a component of Properties and equipment . The stock-based compensation expense has been allocated to lease operations expense, general and administrative expense, and exploration expense. The 2005 statement of operations has been reclassified to conform to the 2006 presentation.

Stock Options

The fair value of each option award granted during the three months ended March 31, 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 three months ended March 31, 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.

	Three months ended	
	March 31, 2006	**March 31, 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 March 31, 2006, and changes during the three 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	(309)	31.10		
Exercised	(22,278)	15.73		
Outstanding at March 31, 2006	1,541,115	14.59	6.8	$ 25,301
Exercisable at March 31, 2006	1,205,985	11.92	6.3	23,005

The weighted average fair value of individual options granted during the three months ended March 31, 2006 was $14.96. The total intrinsic value of options exercised during the three months ended March 31, 2006 and 2005 was $0.4 million and $1.3 million, respectively. The Company received proceeds from the exercise of stock options of $0.4 million and $0.7 million and realized a tax benefit related to the exercises of $0.1 million and $0.4 million during the three months ended March 31, 2006 and 2005, respectively. At March 31, 2006, the Company had $3.2 million of total unrecognized compensation cost related to unvested stock options. That cost is expected to be recognized over a weighted average period of 2.1 years.

Restricted Stock

As of March 31, 2006, there were 665,465 shares of unvested restricted stock outstanding, dependent only on continued employment for vesting. Of this amount, 305,999 shares were granted during the three months ended March 31, 2006. Additionally, as of March 31, 2006, there were 304,601 shares of unvested restricted stock outstanding that depend on continued employment and certain performance measures for vesting. Of this amount, 83,923 shares were granted during the three months ended March 31, 2006.

Table of Contents

A summary of the status of the Company s unvested restricted stock outstanding as of March 31, 2006, and changes during the three months then ended, is presented below:

	Number of Shares	Average Grant Date Fair Value
Outstanding at January 1, 2006	583,274	$ 20.53
Granted	389,922	31.10
Vested		
Forfeited	(3,130)	23.60
Outstanding at March 31, 2006	970,066	24.77

As of March 31, 2006, there was $15.6 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 3.1 years. There were no shares of restricted stock that became vested during the three months ended March 31, 2006 and 2005. Employees may elect to satisfy minimum tax withholding obligations related to vested restricted stock by allowing the Company to withhold shares of common stock at the date of vesting.

11. Comprehensive Income (Loss)

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

	Three months ended March 31, 2006	Three months ended March 31, 2005
Net income	$ 17,936	$ 21,784
Change in unrealized loss on hedged derivative instruments	8,250	(33,539)
Change in deferred gain on interest rate swap	(14)	55
Comprehensive income (loss)	$ 26,172	$ (11,700)

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

	March 31, 2006	December 31, 2005
Unrealized loss on hedged derivative instruments	(64,668)	(72,918)
Deferred gain on interest rate swap	78	92
Accumulated other comprehensive income	(64,590)	(72,826)

12. Financial Statements of Subsidiary Guarantors

As of March 31, 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.

13. Related Party Transactions

The Company paid $0.4 million and $0.1 million to affiliates of Hanover Compressor Company in the three months ended March 31, 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.

14. Subsequent Event

On March 29, 2006, the Company entered into an underwriting agreement under which it agreed to issue and sell 4,000,000 shares of common stock to the public at a price of $32.00 per share. The offering closed on April 4, 2006, with the Company receiving net proceeds of approximately $126.9 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. The net proceeds were used to reduce the amounts outstanding under our revolving credit facility and to pay general corporate expenses. At the completion of the offering, the Company had 52,795,955 shares of common stock outstanding.

Table of Contents

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:

- First Quarter 2006 Highlights
- Results of Operations Comparison of Quarter Ended March 31, 2006 to Quarter Ended March 31, 2005
- Capital Resources
- Capital Commitments
- Liquidity
- Contingencies

First Quarter 2006 Highlights

Our financial and operating results for the quarter ended March 31, 2006 included the following highlights:

- During the first quarter of 2006, we had oil and natural gas revenues of $116.2 million. This represents a 27% increase over the $91.6 million of oil and natural gas revenues reported for the first quarter of 2005.

- We reported net income of $17.9 million, or $0.36 per diluted share, in the three months ended March 31, 2006, as compared to $21.8 million of net income, or $0.44 per diluted share, reported for the first quarter of 2005. The decrease in net income was partially the result of an increase of 24% in total operating expenses per BOE over the first quarter of 2005, which outpaced an increase of 8% in total revenues per BOE over the first quarter of 2005. In the first quarter of 2006, we experienced a significant widening in the differential between the wellhead price we received on our CCA and Williston Basin oil production and the average NYMEX price for oil, which adversely affected our revenues. As Rocky Mountain refiners complete an active turnaround season in the second quarter of 2006, the differential is expected to narrow from first quarter 2006 levels but still remain wider than our historical average.

- Our realized average oil price for the first quarter of 2006, including the effects of hedging, increased $2.80 per Bbl to $42.19 per Bbl as compared to $39.39 per Bbl in the first quarter of 2005. Our realized average natural gas price for the first quarter of 2006, including the effects of hedging, increased $0.66 per Mcf to $6.15 per Mcf as compared to $5.49 per Mcf in the first quarter of 2005.

- Production volumes for the first quarter of 2006 increased 18% to 32,033 BOE per day (2.9 MMBOE for the quarter), compared with first quarter 2005 production of 27,180 BOE per day (2.4 MMBOE for the quarter). The rise in production volumes was attributable to the continued success of our drilling program, uplift from our HPAI tertiary recovery project on the CCA, and acquisitions completed in 2005. Oil represented 65% and 70% of our total production volumes in the first quarter of 2006 and 2005, respectively.

- We invested $68.9 million in oil and natural gas activities during the first quarter of 2006 (excluding development-related asset retirement obligations). We invested $61.2 million in development, exploitation, HPAI expansion, and exploration activities, which yielded 58 gross (25.6 net) wells, and $7.7 million in acquiring proved properties and undeveloped leases. We are currently investing capital in an eight-rig operated drilling program on the onshore continental United States, with three rigs in Montana, two rigs in East Texas, two rigs in Oklahoma, and one rig in North Texas.

Table of Contents

We were able to fund $54.7 million of our investments in oil and natural gas activities using operating cash flows generated during the quarter. The remaining investments were funded through borrowings under our existing revolving credit facility. Long-term debt at March 31, 2006 increased to $692.3 million from $673.2 million at December 31, 2005.

On March 27, 2006, we entered into a joint development agreement with ExxonMobil Corporation to develop seven natural gas fields in West Texas. Under the terms of the agreement, we have the opportunity to develop approximately 100,000 gross acres and will earn 30% of ExxonMobil s working interest in each well drilled. We will operate each well during the drilling and completion phase, after which ExxonMobil will assume operational control of the well. In 2006 and 2007, we intend to drill 22 wells with an investment of $17.0 million and 71 wells with an investment of $55.0 million, respectively, under the joint development agreement.

On March 29, 2006, we entered into an underwriting agreement under which we agreed to issue and sell 4,000,000 shares of common stock to the public at a price of $32.00 per share. The offering closed on April 4, 2006, and we received net proceeds of approximately $126.9 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. The net proceeds were used to reduce the amounts outstanding under our revolving credit facility and to pay general corporate expenses.

Table of Contents

Results of Operations

Comparison of Quarter Ended March 31, 2006 to Quarter Ended March 31, 2005

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

Revenues and Production. The following table illustrates the primary components of oil and natural gas revenues for the three months ended March 31, 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 March 31, 2006	Three months ended March 31, 2005	*Increase / (Decrease)*	
Revenues:				
Oil wellhead	$ 90,679	$ 76,719	*$ 13,960*	
Oil hedges	(11,993)	(9,583)	*(2,410)*	
Total Oil Revenues	$ 78,686	$ 67,136	*$ 11,550*	*17%*
Natural gas wellhead	$ 42,046	$ 25,676	*$ 16,370*	
Natural gas hedges	(4,516)	(1,231)	*(3,285)*	
Total Natural Gas Revenues	$ 37,530	$ 24,445	*$ 13,085*	*54%*
Combined wellhead	$ 132,725	$ 102,395	*$ 30,330*	
Combined hedges	(16,509)	(10,814)	*(5,695)*	
Total Combined Revenues	$ 116,216	$ 91,581	*$ 24,635*	*27%*
Revenues ($/Unit):				
Oil wellhead	$ 48.62	$ 45.01	*$ 3.61*	
Oil hedges	(6.43)	(5.62)	*(0.81)*	
Total Oil Revenues	$ 42.19	$ 39.39	*$ 2.80*	*7%*
Natural gas wellhead	$ 6.89	$ 5.77	*$ 1.12*	
Natural gas hedges	(0.74)	(0.28)	*(0.46)*	
Total Natural Gas Revenues	$ 6.15	$ 5.49	*$ 0.66*	*12%*
Combined wellhead	$ 46.04	$ 41.86	*$ 4.18*	
Combined hedges	(5.73)	(4.42)	*(1.31)*	

Total Combined Revenues	$ 40.31	$ 37.44	*$ 2.87*	*8%*
Total production volumes:				
Oil (Bbls)	1,865	1,704	*161*	*9%*
Natural gas (Mcf)	6,107	4,451	*1,656*	*37%*
Combined (BOE)	2,883	2,446	*437*	*18%*
Daily production volumes:				
Oil (Bbls/day)	20,723	18,937	*1,786*	*9%*
Natural gas (Mcf/day)	67,860	49,455	*18,405*	*37%*
Combined (BOE/day)	32,033	27,180	*4,854*	*18%*
Average NYMEX Prices:				
Oil (per Bbl)	$ 63.48	$ 49.84	*$ 13.64*	*27%*
Natural gas (per Mcf)	7.91	6.47	*1.44*	*22%*

Oil revenues increased $11.6 million from $67.1 million in the first quarter of 2005 to $78.7 million in the first quarter of 2006. The increase is due primarily to an increase in oil production volumes of 161 MBbl, which contributed approximately $7.3

15

Table of Contents

million in additional revenues, and higher realized average oil prices, which contributed approximately $4.3 million in additional revenues. The $4.3 million increase in revenues from higher realized average oil prices consists of a $7.9 million increase resulting from higher average wellhead oil prices, offset by increased hedging payments of $2.4 million, or $0.81 per Bbl, and a $1.2 million charge related to CCA and Williston Basin purchased oil inventory held in pipelines at March 31, 2006. Our average wellhead oil price increased $3.61 per Bbl in the first quarter of 2006 over the first 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 $49.84 in the first quarter of 2005 to $63.48 in the first 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 first quarter of 2006.

Our oil wellhead revenue was reduced by $5.6 million and $3.0 million in the first quarters of 2006 and 2005, respectively, for the net profits interests payments related to our CCA properties.

Natural gas revenues increased $13.1 million from $24.4 million in the first quarter of 2005 to $37.5 million in the first quarter of 2006. The increase is due primarily to increased natural gas production volumes of 1,656 MMcf, which contributed approximately $9.6 million in additional revenues, and higher realized average natural gas prices, which contributed approximately $3.5 million in additional revenues. The $3.5 million increase in revenues from higher realized average natural gas prices consists of a $6.8 million increase resulting from higher average wellhead natural gas prices, offset by increased hedging payments of $3.3 million, or $0.46 per Mcf. Our average wellhead natural gas price increased $1.12 per Mcf in the first quarter of 2006 over the first quarter 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 $6.47 in the first quarter of 2005 to $7.91 in the first quarter 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 quarters ended March 31, 2006 and 2005. Management uses the wellhead to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Three months ended March 31,	
	2006	2005
Oil wellhead ($/Bbl)	$ 48.62	$ 45.01
Average NYMEX ($/Bbl)	$ 63.48	$ 49.84
Differential to NYMEX	$ (14.86)	$ (4.83)
Oil wellhead to NYMEX percentage	77%	90%
Natural gas wellhead ($/Mcf)	$ 6.89	$ 5.77
Average NYMEX ($/Mcf)	$ 7.91	$ 6.47
Differential to NYMEX	$ (1.02)	$ (0.70)
Natural gas wellhead to NYMEX percentage	87%	89%

As indicated above, our oil wellhead price as a percentage of the average NYMEX price decreased to 77% in the first quarter of 2005 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, have created steep pricing discounts. The decrease in the oil differential percentage adversely impacted oil revenues by $18.7 million in the first quarter of 2006 as compared with the first quarter of 2005. As Rocky Mountain refiners complete an active turnaround season in the second quarter of 2006, the differential is expected to narrow from first quarter 2006 levels but still remain wider than our historical average.

Our natural gas wellhead price as a percentage of the average NYMEX price of 87% for the three months ended March 31, 2006 decreased only marginally from the percentages reported for the full year 2005 and the three months ended March 31, 2005 of 88% and 89%, respectively.

Table of Contents

Expenses. The following table summarizes our expenses for the quarters ended March 31, 2006 and 2005:

	Three months ended March 31,		*Increase / (Decrease)*	
	2006	**2005**		
Expenses (in thousands):				
Production -				
Lease operations	$ 22,736	$ 15,149	*$ 7,587*	
Production, ad valorem, and severance taxes	12,242	9,086	*3,156*	
Total production expenses	34,978	24,235	*10,743*	*44%*
Other -				
Depletion, depreciation, and amortization	27,020	16,683	*10,337*	
Exploration	2,009	2,623	*(614)*	
General and administrative	6,528	4,115	*2,413*	
Derivative fair value loss	2,306	2,409	*(103)*	
Other operating	2,529	1,599	*930*	
Total operating	75,370	51,664	*23,706*	*46%*
Interest	11,787	6,959	*4,828*	
Current and deferred income tax provision	11,244	11,238	*6*	
Total expenses	$ 98,401	$ 69,861	$ 28,540	*41%*
Expenses (per BOE):				
Production -				
Lease operations	$ 7.89	$ 6.19	*$ 1.70*	
Production, ad valorem, and severance taxes	4.25	3.71	*0.54*	
Total production expenses	12.14	9.90	*2.24*	*23%*
Other -				
Depletion, depreciation, and amortization	9.37	6.82	*2.55*	
Exploration	0.70	1.07	*(0.37)*	
General and administrative	2.26	1.68	*0.58*	
Derivative fair value loss	0.80	0.98	*(0.18)*	
Other operating	0.88	0.65	*0.23*	
Total operating	26.15	21.10	*5.05*	*24%*
Interest	4.09	2.84	*1.25*	
Current and deferred income tax provision	3.90	4.59	*(0.69)*	
Total expenses	$ 34.14	$ 28.53	$ 5.61	*20%*

Production expenses (Lease operations and production, ad valorem, and severance taxes). Total production expenses increased $10.8 million from $24.2 million in the first quarter of 2005 to $35.0 million in the first quarter of 2006. This increase resulted from an increase in total production volumes, as well as a $2.24 increase in production expenses per BOE. Total production expenses per BOE increased by a larger percentage (23%) than total revenues per BOE (8%) due to increases in the differential between the oil wellhead price we receive and the average NYMEX price in the first quarter of 2006. As a result, our production margin (defined as revenues less production expenses) for the first quarter of 2006 increased to only $28.17 per BOE as compared to $27.54 per BOE for the first quarter of 2005.

The production expense attributable to lease operations increased $7.6 million from $15.1 million in the first quarter of 2005 to $22.7 million in the first quarter of 2006. The increase is due to higher production volumes, which contributed approximately $2.7 million of additional lease operations expense, and an increase in the average per BOE rate, which contributed approximately $4.9 million of additional lease operations expense. The increase in production volumes is the result of our drilling program, the integration of our 2005 acquisitions, and our secondary and tertiary recovery programs, including the waterflood enhancement and high-pressure air injection programs. The increase in our average per BOE rate of $1.70 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. Non-Cash stock compensation in all prior periods presented has been reclassified to allocate the amount to the same respective income statement line 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 & administrative expense, and exploration expense have been changed to reflect the new presentation. This change has resulted in additional lease operations expense of $0.6 million in the first quarter of 2006, or $0.19 per BOE, as compared to $0.3 million in the first quarter of 2005, or $0.11 per BOE.

The production expense attributable to production, ad valorem, and severance taxes (production taxes) for the first quarter of 2006 increased as compared to the same period in 2005 by $3.2 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 $1.6 million of additional production taxes. The average wellhead price we received for oil and natural gas production increased $4.18 per BOE, resulting in additional production taxes of approximately $1.6 million in the first quarter of 2006. As a percentage of oil and natural gas revenues (excluding the effects of hedges), production taxes increased slightly from 8.9% in the first quarter of 2005 to 9.2% in the first 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 $10.3 million from $16.7 million in the first quarter of 2005 to $27.0 in the first quarter of 2006 due to a higher per BOE rate and increased production volumes. The per BOE rate increased $2.55 from the first quarter of 2005 due to the development of proved undeveloped reserves from previous acquisitions, which adds cost but does not increase total proved reserves, and higher drilling costs per BOE of reserves than our historical DD&A rate in certain areas. These factors resulted in additional DD&A expense of $7.3 million. The increase in production volumes of 437 MBOE over the first quarter of 2005 resulted in $3.0 million of additional DD&A expense.

Exploration expense. Exploration expense decreased $0.6 million in the first quarter of 2006 as compared to the first quarter of 2005. During the first quarter of 2006, we expensed two exploratory dry holes, compared to five exploratory dry holes expensed in the first quarter of 2005. The following table details our exploration-related expenses for the first quarter of 2006 and 2005 (in thousands):

	Three months ended March 31,		
	2006	**2005**	***Increase / (Decrease)***
Exploration expenses:			
Dry hole	$ 581	$ 1,320	*$ (739)*
Geological and seismic	438	489	*(51)*
Delay rentals	213	267	*(54)*
Impairment of unproved acreage	777	547	*230*
Total	$ 2,009	$ 2,623	*$ (614)*

General and administrative (G&A) expense. G&A expense increased $2.4 million from $4.1 million in the first quarter of 2005 to $6.5 million in the first quarter of 2006. The overall increase, as well as the $0.58 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 $3.1 million in the first quarter of 2006, or $1.07 per BOE, as compared to $0.5 million in the first quarter of 2005, or $0.20 per BOE. The increase in non-cash stock-based compensation allocated to G&A expense is primarily due to 389,922 shares of restricted stock granted to employees in the first quarter of 2006. G&A expense related to non-cash stock-based compensation in the first quarter 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.

As of March 31, 2006, we had $15.6 million of total unrecognized compensation cost related to unvested restricted stock. We expect to recognize this cost over a weighted average period of 3.1 years. Additionally, we had $3.2 million of total unrecognized compensation cost related to unvested stock options as of March 31, 2006. We expect to recognize this cost over a weighted average period of 2.1 years.

Derivative fair value loss. During the first quarter of 2006 we recorded a $2.3 million derivative fair value loss as compared to a $2.4 million loss recorded in the first quarter of 2005. This derivative fair value loss represents the ineffective portion of the mark-to-market loss on our derivative hedging instruments, settlements received on our fixed-to-floating interest rate swap, (gains) losses related to commodity derivatives not designated as hedges, and changes in the mark-to-market value of our fixed-to-floating interest rate swap.

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

	Three months ended March 31,		***Increase / (Decrease)***
	2006	**2005**	
Designated cash flow hedges:			
Ineffectiveness Commodity contracts	$ 2,839	$ 2,726	*$ 113*
Undesignated derivative contracts:			
Mark-to-market (gain) loss Interest rate swap		180	*(180)*
Mark-to-market (gain) loss Commodity contracts	(533)	(497)	*(36)*
Total derivative fair value (gain) loss	$ 2,306	$ 2,409	*$ (103)*

Ineffectiveness loss related to our derivative commodity contracts increased $0.1 million due primarily to an increase in oil wellhead differentials on our production in the CCA. The interest rate swap loss decreased from the first quarter of 2005 due to the expiration of our fixed-to-floating interest rate swap in June 2005. During the first quarter of 2006, we recognized a gain of $0.5 million related to undesignated commodity contracts, which increased slightly from the first quarter of 2005 due to changes in the fair value of certain natural gas basis swaps.

As we previously discussed, our oil wellhead differentials significantly increased during the first quarter of 2006. Significant and sustained increases in our oil wellhead differentials could preclude the application of hedge accounting to many of our derivative contracts, and should this occur, future mark-to-market gains or losses would be recognized immediately as Derivative fair value (gain) loss in the Consolidated Statements of Operations. This could result in material fluctuations in net income and stockholders equity from period to period.

We have also recently experienced significant fluctuations between the wellhead price we receive on our natural gas production in the North Louisiana Salt Basin and the bases at which that production was hedged with derivative commodity contracts. Continued fluctuations could result in increased ineffectiveness under certain derivative contracts and, ultimately preclude the application of hedge accounting to those contracts, as well.

Other operating expense. Other operating expense increased $0.9 million from $1.6 million in the first quarter of 2005 to $2.5 million in the first 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 first quarter of 2006 over the same period in 2005.

Interest expense. Interest expense increased $4.8 million in the first quarter of 2006 as compared to the first 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 first quarter of 2006 was 6.7% as compared to 7.0% for the same period in 2005. This lower weighted average interest rate is the result of the debt issuances which have rates lower than our historical average rate.

19

Table of Contents

The following table illustrates the components of interest expense for the three months ended March 31, 2006 and 2005 (in thousands):

	Three months ended March 31,		
	2006	**2005**	***Increase / (Decrease)***
$8^{3/8}$% senior subordinated notes due 2012	$	$ 3,141	*$ (3,141)*
$6^{1}/4$% senior subordinated notes due 2014	2,344	2,344	-
6% senior subordinated notes due 2015	4,437		*4,437*
$7^{1}/4$% senior subordinated notes due 2017	2,718		*2,718*
Revolving credit facility	1,362	930	*432*
Other	926	544	*382*
Total	$ 11,787	$ 6,959	*$ 4,828*

Income taxes. Income tax expense for the first quarter of 2006 remained consistent with the first quarter of 2005 at $11.2 million for each period. Our effective tax rate increased in the first quarter of 2006 to 38.5% from 34.0% in the first quarter of 2005 due to the absence of Section 43 income tax credits during the first quarter of 2006. Due to high oil prices in 2005, it is anticipated that the Section 43 credits will be fully phased out and therefore not available in 2006. As a result, we did not adjust our effective tax rate downward in anticipation of generating Section 43 credits for qualifying expenditures made in the first quarter of 2006.

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 decreased slightly from $54.9 million for the three months ended March 31, 2005 to $54.7 million for the three months ended March 31, 2006. Although total revenues in the first quarter of 2006 increased $24.6 million from the first quarter 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 quarter of 2006 caused total revenues per BOE in the first quarter of 2006 to increase only 8% from the first quarter of 2005. The increase in revenues per BOE was largely offset by a 24% increase in total operating expenses per BOE, which resulted in a minimal change in cash provided by operating activities. Total operating expenses increased $23.7 million from $51.7 million for the first quarter of 2005 to $75.4 million for the first quarter of 2006.

Cash flows from financing activities. Our cash flows from financing activities consist primarily of proceeds from and payments on long-term debt. During the first three months of 2006, we received net cash of $15.3 million from financing activities. We periodically draw on our revolving credit facility to fund acquisitions and other capital commitments. In the first quarter of 2006, our total borrowings less repayments on our credit facility resulted in a net increase in the outstanding balance of $19.0 million, from $80.0 million at December 31, 2005 to $99.0 million at March 31, 2006.

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.

During the first three months of 2005, we received net cash of $21.7 million from financing activities. This consisted primarily of a net increase in amounts outstanding under our revolving credit facility of $31.0 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 March 31, 2006, we had total assets of $1.7 billion. Total capitalization as of March 31, 2006 was $1.3 billion, of which 45% was represented by stockholders equity and 55% 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.

On March 29, 2006, we entered into an underwriting agreement to sell 4,000,000 shares of common stock to the public at a price of $32.00 per share. The offering closed on April 4, 2006, and we received net proceeds of $126.9 million, after deducting underwriting discounts and commissions and the estimated expenses of the offering. The net proceeds were used to repay amounts outstanding under our revolving credit facility and for general corporate purposes. On a pro forma basis after giving effect to the offering and the repayment of debt, our total capitalization as of March 31, 2006 would have been $1.3 billion, of which 54% would have been represented by stockholders equity and 46% 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

Table of Contents

Funding of necessary working capital

Payment of contractual obligations

Development, exploitation, and exploration of existing properties. The following table summarizes our costs incurred (excluding asset retirement obligations) related to development, exploitation, and exploration activities during the three months ended March 31, 2006 and 2005 (in thousands):

	Three months ended March 31,	
	2006	**2005**
Development and exploitation	$ 22,869	$ 42,905
Exploration	31,740	7,942
HPAI	6,581	14,697
Total	$ 61,190	$ 65,544

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 March 31, 2006 included a total of 44 gross (19.0 net) successful wells and no development dry holes.

We currently have eight operated rigs drilling on the onshore continental United States with three rigs in Montana, two rigs in Oklahoma, two rigs in East Texas, and one rig in North Texas.

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 March 31, 2006, our exploration capital was invested primarily in drilling extension and exploratory wells in the CCA and Mid-Continent area. In the first three months of 2006, our exploration capital yielded 12 gross (5.5 net) exploratory wells that were productive and 2 gross (1.1 net) exploratory dry holes.

High-pressure air injection programs. In the Pennel unit of the CCA, we have completed Phases 1 and 2 of the HPAI project and are currently expanding to Phase 3. In April 2005, we installed a new HPAI facility capable of injecting 60 million cubic feet per day into the Pennel and Coral Creek units of the CCA, giving us the capacity to complete the development of these units. The Pennel Field is responding to the air injection as expected.

High-pressure air injection in the Little Beaver unit of the CCA was initiated in late 2003, and full implementation of the project was completed in the fourth quarter of 2004. We continue to see a positive production response in line with expectations.

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 months ended March 31, 2006 and 2005 (in thousands):

	Three months ended March 31,	
	2006	**2005**
Acquisitions of proved properties	$ 507	$ 5,671
Leasehold acreage costs	7,182	3,683
Total	$ 7,689	$ 9,354

Acquisitions. Our capital expenditures for proved oil and natural gas properties during the three months ended March 31, 2006 totaled $0.5 million as compared to $5.7 million in the same period in 2005. The $0.5 million of acquisition capital in the first three months of 2006 was invested primarily in additional working interests in the Permian Basin, while the $5.7 million in the first three months of 2005 was invested primarily in additional working interests in the North Louisiana Salt Basin. We do not budget for acquisitions. We will continue to pursue acquisitions of properties with similar upside potential to our current producing properties portfolio.

Table of Contents

Leasehold acreage costs. Our capital expenditures for leasehold acreage costs during the three months ended March 31, 2006 and 2005 totaled $7.2 million and $3.7 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 March 31, 2006 and 2005 totaled $1.0 million and $2.7 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 March 31, 2006, our working capital (defined as total current assets less total current liabilities) was $(40.7) million while at December 31, 2005, our working capital was $(56.8) million, an increase of $16.1 million. The increase is primarily attributable to 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. In April 2006, we received net proceeds of $126.9 million from the issuance of 4.0 million shares of common stock. After paying down the outstanding balance of our revolving credit facility, we had excess cash of $27.9 million from the offering. However, 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.

For the full year 2006, our Board of Directors has approved budgeted capital expenditures of approximately $320.0 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 March 31, 2006 (in thousands):

Contractual Obligations	**Payments Due by Period**				
and Commitments	**Total**	**2006**	**2007 - 2008**	**2009 - 2010**	**Thereafter**
6 1/4% notes (a)	$ 229,675	$ 9,375	$ 18,750	$ 18,750	$ 182,800
6% notes (a)	471,000	9,000	36,000	36,000	390,000
7 1/4% notes (a)	280,500	10,875	21,750	21,750	226,125
Revolving credit facility (a)	130,928	6,386	12,771	111,771	
Derivative obligations (b)	94,720	45,960	48,760		
Development commitments (c)	211,948	66,637	121,872	23,439	
Operating leases (d)	11,216	1,419	3,007	2,754	4,036
Asset retirement obligations (e)	118,398	140	1,165	1,165	115,928
Total	$ 1,548,385	$ 149,792	$ 264,075	$ 215,629	$ 918,889

(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 March 31, 2006. The ultimate settlement amounts of the remaining portions of our derivative obligations are unknown because they are subject to continuing market risk.

(c) Development commitments represent authorized purchases, $25.1 million of which represents work in process and is accrued at March 31, 2006. At March 31, 2006, we had $120.0 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.

Table of Contents

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. 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.

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 three months of 2006 were 9% higher as compared to the first three months of 2005. These prices have historically fluctuated widely in response to changing market forces. For the first three months of 2006, approximately 65% of our production was oil. As we previously discussed, our oil wellhead differentials increased significantly during the first quarter of 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 significant increases in our 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 increases in our wellhead differentials could cause us to not be in compliance with maintenance covenants under our revolving credit facility and thereby affect our liquidity.

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 March 31, 2006 was $550.0 million. The revolving credit facility matures on December 29, 2010.

On March 31, 2006, we had $99.0 million outstanding and $411.0 million available to borrow under the revolving credit facility. On April 4, 2006, we received net proceeds of approximately $126.9 million from the issuance of 4.0 million shares of common stock, after deducting underwriting discounts and commissions and the estimated expenses of the offering. We used the proceeds to pay down the outstanding balance of our revolving credit facility. As a result, on May 1, 2006, we had no amounts outstanding and $475.0 million available to borrow under the credit facility.

As of March 31, 2006, we had $40.0 million in letters of credit posted 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 March 31, 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 May 1, 2006, we had $70.0 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.

Table of Contents

The sale of our CCA oil production is dependent on transportation through Butte Pipeline to markets in the Guernsey, 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 have also been subject to apportionment effective 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 77% in the first quarter of 2005 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, have created deep pricing discounts. As Rocky Mountain refiners complete an active turnaround season in the second quarter of 2006, the differential is expected to narrow from first quarter 2006 levels but still remain wider than our historical average.

You should also 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.

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 10 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.

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 March 31, 2006 are discussed in Note 5 to the accompanying consolidated financial statements. As of March 31, 2006, the fair value of our open commodity derivative contracts was a liability of $79.8 million. Based on our hedged position at March 31, 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 $13.8 million, while a $1 decrease in the NYMEX prices for oil and natural gas would result in a decrease in our derivative fair value liability of approximately $16.1 million.

At March 31, 2006, we had total long-term debt of $692.3 million, which is recorded net of discount of $6.7 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 $7^1/4$%. The remaining outstanding long-term debt balance of $99.0 million is under our revolving credit facility and is subject to floating market rates of interest that are linked to LIBOR.

At the current level of floating rate debt, if the LIBOR rate increased 1%, we would have incurred an additional $0.2 million of interest expense for the three months ended March 31, 2006.

Table of Contents

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 March 31, 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 March 31, 2006 that has materially affected, or is reasonably likely to materially affect, our internal controls over financial reporting.

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 operating results.

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).

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)

Table of Contents

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: May 8, 2006

By: /s/ Robert C. Reeves

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