CONCHO RESOURCES INC
Form 10-Q
May 14, 2008

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

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

For the quarterly period ended March 31, 2008

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: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware	**76-0818600**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
550 West Texas Avenue, Suite 1300 Midland, Texas	**79701**
(Address of principal executive offices)	(Zip code)

(432) 683-7443

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Large accelerated filer o	Accelerated filer o	Non-accelerated filer þ	Smaller reporting company o

(Do not check if a smaller reporting company)

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

Number of shares of the registrant s common stock outstanding at May 13, 2008: 75,984,526 shares.

TABLE OF CONTENTS

PART I Financial Information

ITEM 1. Consolidated financial statements (Unaudited)

Table of Contents

Concho Resources Inc. and subsidiaries
Consolidated balance sheets
Unaudited

(in thousands, except share and per share data)	March 31, 2008	December 31, 2007
Assets		
Current assets:		
Cash and cash equivalents	$ 15,692	$ 30,424
Accounts receivable:		
Oil and gas	41,960	36,735
Joint operations and other	16,047	21,183
Assets held for sale		256
Derivative instruments		1,866
Deferred income taxes	17,797	13,502
Inventory	1,611	1,459
Prepaid insurance and other	2,734	4,017
Total current assets	95,841	109,442
Property and equipment, at cost:		
Oil and gas properties, successful efforts method	1,607,587	1,555,018
Accumulated depletion and depreciation	(188,051)	(167,109)
Total oil and gas properties, net	1,419,536	1,387,909
Other property and equipment, net	9,404	7,085
Total property and equipment, net	1,428,940	1,394,994
Deferred loan costs, net	3,113	3,426
Other assets	434	367
Total assets	$ 1,528,328	$ 1,508,229
Liabilities and stockholders equity		
Current liabilities:		
Accounts payable:		
Trade	$ 4,295	$ 14,222
Related parties	427	2,119
Other current liabilities:		
Bank overdrafts	2,743	5,651
Revenue payable	17,856	14,494
Accrued drilling costs	41,614	39,276
Accrued interest	567	1,590
Other accrued liabilities	13,397	11,935
Derivative instruments	45,540	36,414
Income taxes payable	29	29

Current portion of long-term debt	2,000	2,000
Current asset retirement obligations	1,165	912
Total current liabilities	129,633	128,642
Long-term debt	298,928	325,404
Noncurrent derivative instruments	11,607	10,517
Deferred income taxes	278,083	259,070
Asset retirement obligations and other long-term liabilities	8,309	9,198
Commitments and contingencies (Note K)		
Stockholders equity:		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; and zero shares issued and outstanding at March 31, 2008 and December 31, 2007		
Common stock, $0.001 par value; 300,000,000 authorized; 75,973,689 and 75,832,310 shares issued and outstanding at March 31, 2008 and December 31, 2007, respectively	76	76
Additional paid-in capital	755,510	752,380
Notes receivable from employees		(330)
Retained earnings	59,832	37,467
Accumulated other comprehensive income (loss)	(13,650)	(14,195)
Total stockholders equity	801,768	775,398
Total liabilities and stockholders equity	$ 1,528,328	$ 1,508,229

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

1

Table of Contents

Concho Resources Inc. and subsidiaries
Consolidated statements of operations
Unaudited

(in thousands, except per share amounts)	Three months ended March 31, 2008	2007
Operating revenues:		
Oil sales	$ 75,818	$ 39,371
Natural gas sales	30,893	20,975
Total operating revenues	106,711	60,346
Operating costs and expenses:		
Oil and gas production	7,817	7,259
Oil and gas production taxes	9,078	4,687
Exploration and abandonments	2,741	441
Depreciation and depletion	21,284	19,424
Accretion of discount on asset retirement obligations	153	113
Impairments of proved oil and gas properties	16	1,113
Contract drilling fees stacked rigs		3,354
General and administrative (including non-cash stock-based compensation of $1,299 and $825 for the three months ended March 31, 2008 and 2007, respectively)	7,680	4,292
Ineffective portion of cash flow hedges	(564)	1,255
Loss on derivatives not designated as hedges	17,178	
Total operating costs and expenses	65,383	41,938
Income from operations	41,328	18,408
Other income (expense):		
Interest expense	(5,615)	(10,675)
Other, net	1,020	265
Total other expense	(4,595)	(10,410)
Income before income taxes	36,733	7,998
Income tax expense	(14,368)	(3,375)
Net income	22,365	4,623
Preferred stock dividends		(34)
Net income applicable to common shareholders	$ 22,365	$ 4,589
Basic earnings per share:		
Net income per share	$ 0.30	$ 0.08
Weighted average shares used in basic earnings per share	75,473	54,936

Diluted earnings per share:		
Net income per share	$ 0.29	$ 0.08
Weighted average shares used in diluted earnings per share	76,886	58,840

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

2

Table of Contents

Concho Resources Inc. and subsidiaries
Consolidated statements of stockholders equity
Unaudited

(in thousands)	Common stock Shares	Common stock Amount	Additional paid-in capital	Notes receivable from officers and employees	Retained earnings	Accumulated other comprehensive income (loss)	Total stockholders equity
BALANCE AT DECEMBER 31, 2007	75,832	$ 76	$ 752,380	$ (330)	$ 37,467	$ (14,195)	$ 775,398
Comprehensive income							
Net income					22,365		22,365
Deferred hedge losses, net of tax benefit of $2,582						(4,025)	(4,025)
Net settlement losses included in earnings, net of taxes of $2,932						4,570	4,570
Total comprehensive income							22,910
Stock options exercised	143		1,238				1,238
Restricted stock issued as stock-based compensation	13		394				394
Cancellation of restricted stock	(14)						
Stock-based compensation for stock options			905				905
Excess tax benefits from stock-based compensation			593				593
Proceeds from notes receivable - officers and employees				333			333
Accrued interest employee notes				(3)			(3)
BALANCE AT MARCH 31, 2008	75,974	$ 76	$ 755,510	$	$ 59,832	$ (13,650)	$ 801,768

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

Table of Contents

Concho Resources Inc. and subsidiaries
Consolidated statements of cash flows
Unaudited

	Three months ended March 31,	
(in thousands)	**2008**	**2007**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 22,365	$ 4,623
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and depletion	21,284	19,424
Impairments of proved oil and gas properties	16	1,113
Accretion of discount on asset retirement obligations	153	113
Exploration expense, including dry holes	848	30
Non-cash compensation expense	1,299	825
Gas imbalances	(4)	83
Deferred rent liability	4	(7)
Deferred income taxes	14,368	2,750
Interest accrued on employee notes	(3)	(170)
Amortization of deferred loan costs	313	1,510
Amortization of discount on long-term debt	24	
Gain on sale of property and equipment	(777)	
Ineffective portion of cash flow hedges	(564)	1,255
Loss on derivatives not designated as hedges	17,178	
Dedesignated cash flow hedges reclassed from AOCI	296	
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(281)	10,407
Prepaid insurance and other	1,697	(605)
Excess tax benefits from stock-based compensation	(593)	
Accounts payable	(11,619)	(9,554)
Revenue payable	3,362	1,424
Accrued liabilities	1,462	(27)
Accrued interest	(1,023)	(2,770)
Income taxes payable		625
Net cash provided by operating activities	69,805	31,049
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and gas properties	(51,537)	(36,564)
Additions to other property and equipment	(2,803)	
Proceeds from the sale of oil and gas properties	1,034	
Settlements paid on derivatives not designated as hedges	(3,987)	
Net cash used in investing activities	(57,293)	(36,564)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt		252,900
Payments of long-term debt	(26,500)	(243,400)

Exercise of incentive plan stock options	1,238	
Excess tax benefits from stock-based compensation	593	
Payments of preferred stock dividends		(34)
Proceeds from repayment of officer and employee notes	333	
Payments for loan origination costs		(2,500)
Bank overdrafts	(2,908)	
Net cash provided by (used in) financing activities	(27,244)	6,966
Net increase (decrease) in cash and cash equivalents	(14,732)	1,451
BEGINNING CASH AND CASH EQUIVALENTS	30,424	1,122
ENDING CASH AND CASH EQUIVALENTS	$ 15,692	$ 2,573
SUPPLEMENTAL CASH FLOWS:		
Cash paid for interest and fees, net of $475 and $696 capitalized interest	$ 5,753	$ 12,603
Cash paid for income taxes	$	$

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

4

Concho Resources Inc. and subsidiaries
Condensed notes to consolidated financial statements
Unaudited

Note A. ***Organization and nature of operations***

Concho Resources Inc. (Resources) is a Delaware corporation formed by Concho Equity Holdings Corp. (CEHC) on February 22, 2006, for purposes of effecting the combination of CEHC, Chase Oil Corporation, Caza Energy LLC (Caza) and certain other parties thereto (collectively with Chase Oil Corporation and Caza, the Chase Group). Pursuant to the Combination Agreement dated February 24, 2006, Resources acquired working interests in oil and natural gas properties in Southeast New Mexico from the Chase Group (Chase Group Properties) and issued shares of its common stock to certain stockholders of CEHC in exchange for their capital stock of CEHC. CEHC is a Delaware corporation formed on April 21, 2004 by certain members of the Company s management team and private equity investors. CEHC commenced substantial oil and gas operations in December 2004 upon its acquisition of certain oil and gas properties located in Southeast New Mexico and West Texas. The combination transaction described above (the Combination) was accounted for as an acquisition by CEHC of the Chase Group Properties and a simultaneous reorganization of Resources such that CEHC is now a wholly owned subsidiary of Resources. Prior to the Combination, Resources had no assets, operations or net equity. Upon the closing of the Combination, the executive officers of CEHC became the executive officers of Resources. Resources and its wholly owned subsidiaries are collectively referred to herein as the Company.

CEHC s shareholders received 23,767,691 shares of common stock of Resources in exchange for their preferred and common shares of CEHC, excluding eighteen holders owning an aggregate of 254,621 shares of CEHC 6% Series A Preferred Stock and 127,313 shares of CEHC common stock, as discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes* . In addition, the Chase Group transferred the Chase Group Properties to Resources in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of Resources common stock. In connection with the Company s initial public offering and secondary public offering (both described below), the Chase Group sold a total of 18,638,014 shares of common stock thereby reducing its ownership interest. As of March 31, 2008 and December 31, 2007, the Chase Group owned approximately 17 percent and 21 percent, respectively, of the total outstanding common stock of the Company.

The Company s principal business is the acquisition, development, exploitation and exploration of oil and gas properties in the Permian Basin region of Southeast New Mexico and West Texas.

Initial public offering. On August 7, 2007, the Company completed an initial public offering (the IPO) of its common stock. The Company sold 13,332,851 shares of its common stock in the IPO and certain shareholders, including its executive officers and members of the Chase Group, sold 7,554,256 shares of Resources common stock, in each case, at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.5 million, the Company received net proceeds of approximately $139.2 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,133,066 additional shares of Resources common stock. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.2 million, the Company received net proceeds of approximately $33.8 million. The aggregate net proceeds of approximately $173.0 million received by the Company at closing on August 7, 2007 and August 9, 2007 were utilized in equal amounts to repay a portion of its term loan facility on August 9, 2007, and to prepay a portion of its revolving credit facility on August 20, 2007. See further discussion in Note J *Long-term debt* .

Secondary public offering. On December 19, 2007, the Company completed a secondary public offering of 11,845,000 shares of its common stock, which were sold by certain of its stockholders, including members of the Chase group. The Chase Group sold 10,194,732 shares in the aggregate and certain other stockholders of the Company sold 1,650,268 shares in the aggregate, including one of the Company s executive officers who sold 45,000 shares. Chase Oil Corporation granted the underwriters an option to purchase up to 1,776,615 additional shares to cover over-allotments, which was fully exercised on December 19, 2007. The Company did not receive any proceeds from the sale of its common stock in this secondary offering.

Note B. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of Resources include the accounts of Resources and its wholly owned subsidiaries, including CEHC. All material intercompany balances and transactions have been eliminated.

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company s independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2007 is derived from audited financial statements. In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly the Company s financial position at March 31, 2008, its income for the three months ended March 31, 2008

Table of Contents

and 2007 and its cash flows for the three months ended March 31, 2008 and 2007. All such adjustments are of a normal recurring nature. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed or omitted from these financial statements. Accordingly, these financial statements should be read with the audited consolidated financial statements and notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2007.

Oil and gas sales and imbalances. Oil and gas revenues are recorded at the time of delivery of such products to pipelines for the account of the purchaser or at the time of physical transfer of such products to the purchaser. The Company follows the sales method of accounting for oil and gas sales, recognizing revenues based on the Company s share of actual proceeds from the oil and gas sold to purchasers. Oil and gas imbalances are generated on properties for which two or more owners have the right to take production in-kind and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable to or payable from the other owners unless the imbalance has reached a level whereby it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance.

At March 31, 2008, the Company had a gas imbalance liability, included in *Asset retirement obligations and other long-term liabilities* in the accompanying consolidated balance sheet of approximately $604,000 related to the Company s overtake position of 94,423 Mcf on certain wells and a gas imbalance receivable, included in *Other assets* in the accompanying consolidated balance sheet of approximately $354,000 related to the Company s undertake position of 78,764 Mcf on certain wells.

General and administrative expense. The Company receives fees for its operation of jointly owned oil and gas properties and records such reimbursements as reductions of General and administrative expense. Such fees totaled approximately $239,000 and $409,000 for the three months ended March 31, 2008 and 2007, respectively.

Note C. *Exploratory well costs*

Costs of drilling exploratory wells are capitalized, pending management s determination of whether the wells have found proved reserves. If proved reserves are found, the costs remain capitalized. If proved reserves are not found, the capitalized costs of drilling the well are charged to expense. Management makes this determination as soon as possible after completion of drilling considering the guidance provided in Financial Accounting Standards Board (FASB) Statement of Financial Accounting Standards (SFAS) No. 19, Financial Accounting and Reporting by Oil and Gas Producing Companies and FASB Staff Position (FSP) No. 19-1 Accounting for Suspended Well Costs.

The following table provides an aging, as of March 31, 2008 and December 31, 2007, of capitalized exploratory well costs based on the date drilling was completed:

(in thousands)	**March 31, 2008**	**December 31, 2007**
Wells in progress	$ 2,512	$ 4,199
Capitalized exploratory well costs that have been capitalized for a period of one year or less	26,522	16,857
Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Total exploratory well costs	$ 29,034	$ 21,056

As of March 31, 2008, the capitalized exploratory well costs of approximately $29.0 million had been deferred for a period of one year or less and were related primarily to the Company s New Mexico Shelf properties and emerging resource plays.

As of December 31, 2007, the capitalized exploratory well costs of approximately $21.1 million had been deferred for a period of one year or less and were related primarily to the Company s New Mexico Shelf and New Mexico Basin properties.

Table of Contents

Note D. ***Fair value measurements***

The Company adopted SFAS No. 157, Fair Value Measurements, (SFAS No. 157) effective January 1, 2008 for financial assets and liabilities measured on a recurring basis. SFAS No. 157 applies to all financial assets and financial liabilities that are being measured and reported on a fair value basis. In February 2008, the FASB issued FSP No. 157-2, which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS No. 157 requires disclosure that establishes a framework for measuring fair value and expands disclosure about fair value measurements. The statement requires fair value measurements be classified and disclosed in one of the following categories:

Level 1: Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. We consider active markets as those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that we value using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps. Our valuation models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. We utilize our counterparties valuations to assess the reasonableness of our prices and valuation techniques.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity). Level 3 instruments primarily include derivative instruments such as commodity price collars and floors. Our valuation models are primarily industry-standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value, (c) volatility factors and (d) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although we utilize our counterparties valuations to assess the reasonableness of our prices and valuation techniques, we do not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Table of Contents

As required by SFAS No. 157, financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following table summarizes the valuation of the Company s financial instruments by SFAS No. 157 pricing levels as of March 31, 2008:

	Fair value measurements using			
(in thousands)	Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total carrying value at March 31, 2008
Oil and natural gas derivative price swap contracts	$	$ (52,326)	$	$ (52,326)
Natural gas derivative price collar contract			(4,767)	(4,767)
Total derivative assets (liabilities)	$	$ (52,326)	$ (4,767)	$ (57,093)

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as level 3 in the fair value hierarchy (in thousands):

(in thousands)	Derivatives
Balance as of January 1, 2008	$ 1,866
Total gains or (losses) (realized or unrealized)	(6,583)
Purchases, issuances, and settlements	(50)
Transfers in and/or out of Level 3	
Balance as of March 31, 2008	$ (4,767)
Total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets and/or liabilities still held at the reporting date	$ (6,633)

Note E. ***New accounting pronouncements***

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, which will become effective in 2008. SFAS No. 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. The Company adopted this statement January 1, 2008, and the Company did not elect the fair value option for any of its eligible financial instruments or other items. As such, the adoption had no impact on the Company s consolidated financial statements.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FIN No. 39-1). FIN No. 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FIN No. 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company adopted FIN No. 39-1 effective January 1, 2008, and it has had no material impact on the Company s consolidated financial statements.

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s

Table of Contents

estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The consensus in EITF Issue 06-11 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2007. Retrospective application of EITF Issue 06-11 is not permitted. Early adoption is permitted; however, the Company did not adopt EITF Issue 06-11 until the required effective date of January 1, 2008. The adoption of EITF Issue 06-11 has not had a significant effect on the Company s financial statements since it historically has accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), which replaces FASB Statement No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non- controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be the Company s fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations the Company consummates after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51. SFAS No. 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be the Company s fiscal year 2009. Based upon the Company s March 31, 2008 consolidated balance sheet, the statement would have no impact.

In December 2007, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) No. 110, Share-Based Payment (SAB No. 110). SAB No. 110 amends SAB No. 107, Share-Based Payment, and allows for the continued use, under certain circumstances, of the simplified method in developing an estimate of the expected term on stock options accounted for under SFAS No. 123R, Share-Based Payment (revised 2004). SAB No. 110 is effective for stock options granted after December 31, 2007. The Company continued to use the simplified method in developing an estimate of the expected term on stock options granted in the first quarter of 2008. The Company does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its shares of common stock have been publicly traded.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161), which amends and expands the disclosure requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to provide an enhanced understanding of an entity s use of derivative instruments, how they are accounted for under SFAS No. 133 and their effect on the entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective as of January 1, 2009. The Company is currently evaluating the impact on its consolidated financial statements of adopting SFAS No. 161.

Note F. ***Asset retirement obligations***

The Company s asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their production lives, in accordance with applicable state laws. The Company does not provide for a market risk premium associated with asset retirement obligations because a reliable estimate cannot be determined. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

Table of Contents

The following table summarizes the Company s asset retirement obligation transactions recorded in accordance with the provisions of SFAS No. 143 during the three months ended March 31, 2008 and 2007:

(in thousands)	Three months ended March 31, 2008	2007
Asset retirement obligations, beginning of period	$ 9,418	$ 8,700
Liability incurred upon acquiring and drilling wells	34	33
Accretion expense	153	113
Liabilities settled upon plugging and abandoning wells		
Revisions to estimated cash flows	(810)	(400)
Asset retirement obligations, end of period	$ 8,795	$ 8,446

Note G. ***Stockholders equity and stock issued subject to limited recourse notes***

Equity commitments. Pursuant to a stock purchase agreement (the Stock Purchase Agreement) entered into on August 13, 2004, the Company obtained private equity commitments totaling $202.5 million, comprised of equity commitments from fourteen private investors (the Private Investors) of approximately $188.9 million and equity commitments from the five original officers (the Officers) of the Company in the aggregate amount of $13.6 million. The original commitments were subject to call by a vote of the board of directors over a four year period beginning August 13, 2004 (the Take-Down Period), with the first date on which capital was called being August 13, 2004. Subsequent calls were made on November 11, 2004, June 22, 2005, December 7, 2005 and February 10, 2006. The percentage of total commitments called per capital call date was approximately 15.0 percent, 23.3 percent, 10.0 percent, 15.0 percent and 22.0 percent, respectively. In conjunction with the exchange of CEHC common stock for Resources common stock as of the date of the Combination, the remaining 14.7 percent of these private equity commitments was terminated.

In addition to this arrangement between the Private Investors and the Officers, certain employees and executive officers of the Company entered into separate subscription agreements with the Company. The officers and employees equity purchases were paid in a combination of cash and the issuance of notes payable to the Company with recourse only to any equity security of the Company held by the respective officer or employee (the Purchase Notes). Based on guidance contained in SFAS No. 123R, the agreements to sell stock to the Officers and certain employees subject to Purchase Notes are accounted for as the issuance of options (Bundled Capital Options for the Officers and Capital Options for certain employees) on the dates that the various subscription agreements were signed and the purchase commitments were made.

Capital calls. From inception of the Company through February 23, 2006, the Private Investors purchased 16,113,170 Preferred Units for $161.1 million in cash. The Officers had purchased 2,240,083 CEHC common shares and 938,303 Preferred Units for $3.6 million in cash and Purchase Notes totaling $8.0 million. Certain employees purchased 425,221 Preferred Units for $1.0 million in cash and Purchase Notes totaling $3.8 million.

6% Series A preferred stock. Preferred stock dividends were generally paid on the anniversary of date of issue. There were no dividend payments made during the three months ended March 31, 2008, because there was no outstanding preferred stock. Preferred stock dividends of approximately $34,000 were paid during the three months ended March 31, 2007. As discussed in Note A *Organization and nature of operations* and below, the majority of the CEHC preferred stock was converted into Resources common stock on the Combination date. Final dividend payments on converted CEHC 6% Series A Preferred Stock were made in March 2006.

Dividend payments continued to be made to the eighteen employee shareholders that did not convert their shares of CEHC preferred stock to Resources common stock through April 16, 2007. On April 16, 2007, these CEHC preferred shares were exchanged for 190,972 shares of the Company s common stock. These shares are reported as if converted on the Combination date. Final dividend payments on this final portion of converted CEHC 6% Series A Preferred Stock were made on April 16, 2007.

Purchase Notes. On April 23, 2007, the Company s executive officers repaid their Purchase Notes in full, including principal of $9,426,000 and accrued interest of $1,037,000. The agreements to sell stock to the executive officers of the Company subject to Purchase Notes were accounted for as the issuance of options. As such, the repayment of the executive officer Purchase Notes represents the full exercise of the options on the Bundled Capital Options (as defined below) the Officers held as well as the Capital Options (as defined below) of one certain employee who is currently an executive officer.

At March 31, 2008, all Purchase Notes from all employees had been paid in full. As such, the repayment of the Purchase Notes represents the full exercise of the options on the Capital Options the certain employees held.

The following table summarizes the Capital Options activity for the three months ended March 31, 2008:

	Number of Capital Options		Weighted average exercise price
Three months ended March 31, 2008			
Outstanding at beginning of period	38,385	$	8.34
$10 Capital Options exercised	(38,385)	$	8.34
Cancelled / forfeited		$	
Outstanding at end of period		$	
Vested outstanding at end of period		$	

Conversion of CEHC 6% Series A Preferred Stock and CEHC common stock. On February 27, 2006, concurrent with the closing of the Combination described in Note A *Organization and nature of operations*, the majority of the shares of CEHC preferred stock and shares of CEHC common stock outstanding were converted to shares of Resources common stock, as described below.

Eighteen employee shareholders owning an aggregate of 254,621 shares of CEHC preferred stock and 127,313 shares of CEHC common stock did not convert their shares to Resources common stock at the date of the Combination. On April 16, 2007, these remaining shares of CEHC were exchanged for 318,285 shares of the Company s common stock. These shares are reported as if converted on the Combination date. In addition, CEHC made a final dividend payment to these eighteen employee shareholders on their CEHC preferred stock in the aggregate amount of approximately $99,000 on April 16, 2007.

Also in conjunction with the Combination described in Note A *Organization and nature of operations* and the conversion of CEHC preferred stock into Resources common stock at the ratio of 0.75:1, the CEHC Bundled Capital Options were converted into Resources Bundled Capital Options and CEHC Capital Options were converted into Resources Capital Options. The Resources Capital Options are considered to be exercisable for 1.25 shares of Resources common stock.

Note H. *Stock incentive plan*

The Concho Resources Inc. 2006 Stock Incentive Plan (together with applicable option agreements and restricted stock agreements, the Plan) provides for granting stock options and restricted stock awards to employees and individuals associated with the Company.

Restricted stock awards. On April 23, 2007, the Company issued a total of 20,000 shares of restricted common stock comprised of 2,500 shares to each of its then eight outside directors, subject to certain restrictions as set forth in the Plan. Time related restrictions lapsed with respect to 100 percent of the restricted shares on the date of grant. The grant date fair value of the stock was estimated to be approximately $340,000 which the Company recognized as stock-based compensation expense in April 2007.

In August 2007, the Company s board of directors appointed a new non-employee director who was granted 5,000 shares of restricted common stock by the compensation committee of the Company s board of directors in accordance with the Company s non-employee director compensation plan, subject to certain restrictions as set forth in the Plan and a restricted stock agreement between the Company and such director. These restrictions lapse with respect to 100 percent of the restricted shares twelve months from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $64,000, which the Company will recognize as stock-based compensation expense over a twelve month period beginning August 2007.

In September 2007, the compensation committee of the Company s board of directors approved the grant of 112,540 shares of restricted common stock in the aggregate to the non-officer employees of the Company, subject to certain restrictions as set forth in the Plan and respective restricted stock agreements between the Company and each such employee. These restrictions lapse with respect to 100 percent of the restricted shares three years from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $1,629,000 which the Company will recognize as stock-based compensation expense over the next three years beginning September 2007.

Table of Contents

In February 2008, the compensation committee of the Company s board of directors approved the grant of 12,500 shares of restricted common stock in the aggregate to certain non-employee directors of the Company, under the Company s outside director compensation plan, subject to certain restrictions as set forth in the Plan and respective restricted stock agreements between the Company and each such director; these grants included a grant of 5,000 shares to a new non-employee director. These restrictions lapse with respect to 100 percent of the restricted shares twelve months from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $273,000 which the Company will recognize as stock-based compensation expense over a twelve month period beginning March 2008.

All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If a grantee terminates employment or other services prior the lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding, subject to the discretion of the compensation committee. A summary of the Company s restricted stock awards during the three months ended March 31, 2008 is presented below:

	Number of common shares	Grant date fair value
Restricted stock:		
Outstanding at December 31, 2007	371,549	
Shares granted	12,500	$ 21.84
Shares cancelled / forfeited	(13,873)	
Lapse of restrictions	(20,814)	
Outstanding at March 31, 2008	349,362	

The Company recorded stock-based compensation for restricted stock of $394,000 and $221,000, which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations, for the three months ended March 31, 2008 and 2007, respectively. Future stock-based compensation expense related to restricted stock outstanding at March 31, 2008 for the remaining nine months of 2008 and the years ending December 31, 2009 and 2010 is expected to be approximately $1,297,000, $1,039,000 and $404,000, respectively. The income tax benefit recognized in the accompanying statement of operations for restricted stock was approximately $154,000 and $93,000 for the three months ended March 31, 2008 and 2007, respectively.

Stock option awards. On August 15, 2007, the compensation committee awarded an option to purchase 200,000 shares of the Company s common stock to a new officer of the Company and an option to purchase 15,000 shares of the Company s common stock to a non-officer employee of the Company under the Plan. These options have an exercise price of $12.85, a contractual term of 10 years from the date of grant, and vest using a four year graded vesting schedule.

During the three months ended March 31, 2008, the compensation committee awarded options to purchase 20,000 shares of the Company s common stock in the aggregate to two non-officer employees and options to purchase 470,000 shares of the Company s common stock in the aggregate to the executive officers of the Company under the Plan. These 490,000 options have a weighted average exercise price of $21.84, a contractual term of 10 years from the date of grant, and vest using a four year graded vesting schedule.

In calculating the compensation expense for these 2008 options, the Company estimated the fair value of each grant using the Black-Scholes option-pricing model. Assumptions utilized in the model are shown below.

	2008

Risk-free interest rate	3.17%
Expected term (years)	6.25
Expected volatility	36.69%
Expected dividend yield	0.00%

As permitted by SAB No. 110, the Company used the simplified method to calculate the expected term for stock options granted during the three months ended March 31, 2008, since it does not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its shares of common stock have been publicly traded.

Table of Contents

A summary of the Company s stock option activity under the Plan for the three months ended March 31, 2008 is presented below:

	Three months ended March 31, 2008	
	Number of options[(a)]	Weighted Average Exercise Price
Stock options:		
Outstanding at beginning of period	3,011,722	$ 9.71
Options granted	490,000	$21.84
Options forfeited	(128,458)	$15.55
Options exercised	(142,752)	$ 8.68
Outstanding at end of period	3,230,512	$11.37
Exercisable at end of period	729,509	$ 9.52

(a) One option can be exercised for one share of Resources common stock.

The following table summarizes information about the Company s vested stock options outstanding and exercisable at March 31, 2008:

		Number vested and exercisable	Weighted average remaining contractual life	Weighted average exercise price	Intrinsic value
Vested Options					
March 31, 2008					
Exercise price	$ 8.00	1,635,158	3.03 years	$ 8.00	$ 28,844,000
Exercise price	$ 12.00	173,089	5.77 years	$ 12.00	2,361,000
Exercise price	$ 15.40	112,500	8.21 years	$ 15.40	1,152,000
		1,920,747		$ 8.79	$ 32,357,000

Exercisable Options					
March 31, 2008					
Exercise price	$ 8.00	526,594	3.60 years	$ 8.00	$ 9,289,000
Exercise price	$ 12.00	115,415	7.27 years	$ 12.00	1,574,000
Exercise price	$ 15.40	87,500	8.21 years	$ 15.40	896,000
		729,509		$ 9.52	$ 11,759,000

13

Table of Contents

The following table summarizes information about stock-based compensation for options which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations for the three months ended March 31, 2008 and 2007:

	Three months ended March 31, 2008	2007
Grant date fair value:		
Time Vesting options [a]	$ 183,000	$
Performance Vesting options:		
Officers [b]		
Certain employee [b]		
Non-officers [c]		
Current officer stock options [d]	4,296,000	
Total	$4,479,000	$
Stock-based compensation expense from stock options:		
Time Vesting options [a]	$ 30,000	$
Performance Vesting options:		
Officers [b]	140,000	138,000
Certain employee [b]	10,000	
Non-officers [c]		10,000
Current officer stock options [d]	725,000	456,000
Total	$ 905,000	$604,000

(a) Options vest using a four year graded vesting schedule.

(b) Options granted prior to February 27, 2006, vests using a three year graded vesting schedule.

(c) Vested upon consummation

of the Combination by approval from CEHC s Board of Directors.

(d) Vest using a four year graded vesting schedule as approved by the Board of Directors.

Future stock-based compensation expense related to stock options outstanding at March 31, 2008 for the remaining nine months ended December 31, 2008 and the years ending December 31, 2009, 2010, 2011 and 2012 is expected to be approximately $3,252,000, $2,230,000, $1,012,000, $385,000 and $42,000, respectively.

The income tax benefit recognized in the Company s statements of operations for these stock-based compensation arrangements was $354,000 and $255,000 for the three months ended March 31, 2008 and 2007, respectively. The Company had deductions in current taxable income of $2.2 million for the three months ended March 31, 2008, as options on 142,752 shares of common stock were exercised during such quarter. No amounts were treated as deductions to the Company s current taxable income for the three months ended March 31, 2007, since no options were exercised during such quarter.

Note I. *Derivative financial instruments*

Cash flow hedges. The Company, from time to time, uses derivative financial instruments as cash flow hedges of its commodity price risks. Commodity hedges are used to (a) reduce the effect of the volatility of price changes on the natural gas and crude oil the Company produces and sells and (b) support the Company s annual capital budgeting and expenditure plans.

Through December 31, 2006, the Company had entered into certain natural gas and crude oil zero cost price collars and crude oil price swaps to hedge a portion of its estimated natural gas and crude oil production for calendar years 2007 and 2008.

On February 8, 2007, the Company entered into one natural gas price swap to hedge an additional portion of its estimated natural gas production for the period of March through December 2007. The contract is for 2,100 MMBtu per day at a fixed index price of

$7.40 per MMBtu. The index price is based on the Inside FERC El Paso Permian Basin spot price at the first of each month. On the respective trade dates, the Company has designated all of these derivative instruments as cash flow hedges.

During the three months ended September 30, 2007, the Company determined that all of its natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended (SFAS No. 133) for the reason stated in the following paragraph. These contracts are referred to as dedesignated hedges.

A key requirement for designation of derivative instruments as cash flow hedges is that at both at inception of the hedge and on an ongoing basis, the hedging relationship is expected to be highly effective in achieving offsetting cash flows attributable to the hedged risk during the term of the hedge. Generally, the hedging relationship can be considered to be highly effective if there is a high degree of historical correlation between the hedging instrument and the forecasted transaction. For all quarters ended prior to July 1, 2007, prices received for the Company s natural gas were highly correlated with the Inside FERC El Paso Natural Gas index (the Index) the Index referenced in all of the Company s natural gas derivative instruments. However, during the quarter ended September 30, 2007, this historical relationship has not met the criteria as being highly correlated. Natural gas produced from the Company s New Mexico Shelf assets has a substantial component of natural gas liquids. Prices received for natural gas liquids are not highly correlated to the price of natural gas, but are more closely correlated to the price of oil. During the third quarter of 2007, the price of oil and natural gas liquids, and therefore, the prices the Company received for its natural gas (including natural gas liquids) have risen substantially and at a significantly higher rate than the corresponding change in the Index. This has resulted in a decrease in correlation between the prices received and the Index below the level required for cash flow hedge accounting. According to SFAS No. 133, an entity shall discontinue hedge accounting prospectively for an existing hedge if the hedge is no longer highly effective. Hedge accounting must be discontinued regardless of whether the Company believes the hedge will be prospectively highly effective. The hedge must be discontinued during the period the hedges became ineffective. As a result, any changes in fair value must be recorded in earnings under *(Gain) loss on derivatives not designated as hedges*. Because the gas and liquids prices fluctuate at different rates over time, the loss of effectiveness does not relate to any single date.

Therefore, June 30, 2007, was considered the last date the Company s natural gas hedges were highly effective, and the Company discontinued hedge accounting during the three months ended September 30, 2007 and all periods thereafter. Mark-to-market adjustments related to these dedesignated hedges is recorded each period to *(Gain) loss on derivatives not designated as hedges*. Effective portions of dedesignated hedges, previously recorded in *Accumulated other comprehensive income* (*AOCI*) as of June 30, 2007, remain in *AOCI* and are being reclassified into earnings under *Natural gas revenues*, during the periods which the hedged forecasted transaction affects earnings.

Derivatives not designated as cash flow hedges. On September 20, 2007, the Company entered into four crude oil price swaps to hedge an additional portion of its estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,000 Bbls per day each with various fixed prices. The Company has not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

On March 3, 2008, the Company entered into two crude oil price swaps to hedge a portion of its estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,400 Bbls per day for the remainder of 2008 (April through December) at a fixed price of $99.25 per Bbl, and 800 Bbls per day for calendar year 2009 at a fixed price of $98.35 per Bbl. The Company has not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

On March 11, 2008, the Company entered into a natural gas price swap to hedge a portion of its estimated natural gas production for calendar year 2009. The contract is for 5,000 MMBtus per day with a fixed price of $8.44. The Company has not designated this derivative instrument as a cash flow hedge. Mark-to-market adjustments related to this derivative instrument will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

Fair value and activity of derivative instruments. The following table sets forth the Company s outstanding crude oil and natural gas zero cost price collars and price swaps at March 31, 2008:

	Fair Market Value Asset / (Liability) (in thousands)	Aggregate remaining volume	Daily volume	Index price	Contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	$ (22,779)	715,000	2,600	$ 67.50(a)	4/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	(4,767)	3,712,500	13,500	$ 6.50-$9.35(b)	4/1/08 - 12/31/08
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(13,118)	935,000	3,400	$ 85.44(a) (c)	4/1/08 - 12/31/08
Price swap	(15,819)	1,022,000	2,800	$ 80.13(a) (c)	1/1/09 - 12/31/09
Natural gas (volumes in MMBtus):					
Price swap	(610)	1,825,000	5,000	$ 8.44(b)	1/1/09 - 12/31/09
Net liability	$ (57,093)				

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian

Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

The following table sets forth the Company s classification of derivative instruments as of March 31, 2008:

(in thousands)		**Fair Market Value Asset / (Liability)**
Long-term derivative assets	$	54 [(a)]
Derivative liabilities:		
Short-term		(45,540)
Long-term		(11,607)
Net liability	$	(57,093)

[(a)] Classified on the consolidated balance sheet in Other long-term assets.

Table of Contents

The Company s reported oil and gas revenue and average oil and gas prices includes the effects of oil quality and Btu content, gathering and transportation costs, gas processing and shrinkage, and the net effect of the commodity hedges. The following table summarizes the gains and losses reported in earnings related to the commodity financial instruments and the net change in *AOCI:*

	Three months ended March 31,	
(in thousands)	**2008**	**2007**
Increase (decrease) in oil and gas revenue from derivative activity:		
Cash (payments) receipts on cash flow hedges in oil sales	$ (7,206)	$ 1,027
Cash receipts from cash flow hedges in gas sales		138
Dedesignated cash flow hedges reclassed from AOCI in gas sales	(296)	
Total increase (decrease) in oil and gas revenue from derivative activity	$ (7,502)	$ 1,165
Gain (loss) on derivatives not designated as cash flow hedges:		
Mark-to-market	$(13,191)	$
Cash receipts (payments) on derivatives not designated as cash flow hedges	(3,987)	
Total gain (loss) on derivatives not designated as cash flow hedges	$(17,178)	$
Gain (loss) from ineffective portion of cash flow hedges	$ 564	$(1,255)
Accumulated other comprehensive income (loss):		
Cash flow hedges:		
Mark-to-market of cash flow hedges gain (loss)	$ (6,607)	$(8,449)
Reclassification adjustment for (gains) losses included in net income	7,206	(1,165)
Net change, before taxes	599	(9,614)
Tax effect	(234)	4,012
Net change, net of tax	$ 365	$(5,602)
Dedesignated cash flow hedges:		
Reclassification adjustment for (gains) losses included in net income	$ 296	$
Tax effect	(116)	
Net change, net of tax	$ 180	$

All of the Company s derivatives are expected to settle by January 8, 2010. Based on futures prices as of March 31, 2008, the Company expects a pre-tax loss of $22,007,000 to be reclassified into earnings and a pre-tax gain of

$400,000 to be reclassified out of *AOCI* into earnings during the twelve months ended March 31, 2009 related to the cash flow hedges and the dedesignated cash flow hedges, respectively.

Table of Contents

Note J. ***Long-term debt***

The Company s long-term debt consists of the following:

(in thousands)	March 31, 2008	December 31, 2007
Bank debt:		
1st Lien Credit Facility	$190,000	$216,000
2nd Lien Credit Facility		
New 2nd Lien Credit Facility	109,400	109,900
Unamortized original issue discount on New 2nd Lien Credit Facility	(472)	(496)
Total long-term debt	$298,928	$325,404
Current portion of New 2nd Lien Credit Facility	2,000	2,000
Total debt	$300,928	$327,404

1st Lien Credit Facility. As of February 24, 2006, the Company entered into a credit agreement with a syndicate of banks (the 1st Lien Banks) which provides for a revolving credit facility (the 1st Lien Credit Facility) with commitments from the 1st Lien Banks aggregating $475 million, subject to a borrowing base. The borrowing base is calculated based on the Company s oil and gas reserves. The maturity date of the 1st Lien Credit Facility is February 24, 2010. The Company may also request the issuance of letters of credit up to $20 million. The borrowing commitment is reduced by any outstanding letters of credit.

The initial borrowing base under the 1st Lien Credit Facility was $475 million. The borrowing base is redetermined semiannually as of January 1 and June 30 of each year. In addition to the scheduled redeterminations, the Company and the 1st Lien Banks are each provided the option to request an additional redetermination once between the scheduled redeterminations. The Company entered into the Second Amendment to the 1st Lien Credit Facility on March 27, 2007. The amendment allowed for the incurrence of additional indebtedness in the form of a $200 million second lien term loan. Various amendments have redetermined the borrowing base under the 1st Lien Credit Facility, which was $425 million as of March 31, 2008.

Advances on the 1st Lien Credit Facility bear interest, at the Company s option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (5.25 percent at March 31, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 100 - 225 basis points and 0 - 125 basis points, respectively, per annum depending on the balance outstanding. The Company pays commitment fees on the unused portion of the available borrowing base ranging from 25 - 50 basis points per annum. The Company used a portion of the net proceeds from its IPO to retire outstanding borrowings under the 1st Lien Credit Facility totaling $86.6 million. The amount outstanding under this facility at March 31, 2008 was $190.0 million, all of which was at the Eurodollar rate.

The 1st Lien Credit Facility also includes a same-day advance facility under which the Company may borrow funds on a daily basis from the 1st Lien Banks administrative agent. Advances made on this same-day basis cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin. There were no amounts outstanding on this facility at March 31, 2008.

The Company s obligations under the 1st Lien Credit Facility are secured by a first lien on substantially all of the Company s oil and gas properties. In addition, all but one of the Company s subsidiaries are guarantors, and all subsidiary general partner, limited partner and membership interests owned by the Company have been pledged to secure borrowings under the 1st Lien Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses no greater than 4.0 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be no less than 1.0 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to merger and sale or transfer of assets; and (d) a restriction on the payment of cash dividends. The Company was in compliance with all covenants of the 1st Lien Credit Facility at March 31, 2008.

Refinancing of debt facilities. As of March 27, 2007, the Company amended its 1st Lien Credit Facility, repaid an existing second lien credit facility, and entered into a new second lien credit facility (the New 2nd Lien Credit Facility), for a term loan facility in the amount of $200 million. The full amount of the facility was funded on the closing date. The New 2nd Lien Credit

Facility was issued at a discount of 0.5 percent; thus, the Company received proceeds of $199.0 million. The proceeds from the borrowing were used to repay the existing second lien credit facility in full in the amount of $39.8 million without penalty, reduce the amount outstanding under the 1st Lien Credit Facility by $154.0 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes.

The amendment of the 1st Lien Credit Facility on March 27, 2007, resulted in a $100 million, or 21 percent, reduction of the borrowing base. As such, the pro rata portion of the remaining debt issuance costs associated with the 1st Lien Credit Facility, totaling approximately $766,000, was written off and included in *Interest expense* in the first quarter of 2007. The remaining debt issuance costs of $433,000 associated with the second lien credit facility repaid in full on March 27, 2007, were written off and included in *Interest expense* in the first quarter of 2007.

The Company paid an arrangement fee of $2.5 million at the date of closing of the New 2nd Lien Credit Facility. This fee is being amortized to *Interest expense* over the five-year term of the facility beginning in April 2007.

The New 2nd Lien Credit Facility provides a $200 million term loan, which bears interest, at the Company s option, based on (a) the Bank of America Prime Rate (5.25 percent at March 31, 2008) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and prime rate advances vary, with interest margins of 375 basis points and 225 basis points, respectively, until the sooner to occur of an initial public offering by the Company or the first anniversary of the closing date of the loan; thereafter, interest margins on Eurodollar rate advances and prime rate advances will be 425 basis points and 275 basis points, respectively. The Company may select interest periods on Eurodollar rate advances of one, two, three, six, nine and twelve months, subject to availability. Interest is payable at the end of the selected interest period, but no less frequently than quarterly.

The Company is required to repay $0.5 million of the New 2nd Lien Credit Facility on the last day of each calendar quarter. These payments began on June 30, 2007. The maturity date of the New 2nd Lien Credit Facility is March 27, 2012. The Company has the right to prepay the outstanding balance under the New 2nd Lien Credit Facility at any time; however, a two percent prepayment penalty will be incurred on any principal amount prepaid during the second year following the closing and one percent penalty will be incurred during the third year following the closing. Thereafter, no prepayment penalty will be incurred.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing the 1st Lien Credit Facility. The second lien is subordinated only to liens securing the 1st Lien Credit Facility. The New 2nd Lien Credit Facility contains various restrictive covenants including (a) maintenance of certain financial ratios including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other non-cash income and expenses of less than 4.5 to 1.0, (ii) maintenance of a ratio of current assets to current liabilities, excluding non-cash assets and liabilities related financial derivatives and asset retirement obligations, to be greater than 1.0 to 1.0 and (iii) maintenance of a ratio, as of January 1 and June 30 of each year, of the net present value of the Company s oil and gas properties to total debt to be greater than 1.5 to 1.0; (b) limits on the incurrence of additional indebtedness and certain types of liens; (c) restrictions as to merger and sale or transfer of assets; and (d) a restriction on the payment of cash dividends. The Company was in compliance with all covenants of the New 2nd Lien Credit Facility at March 31, 2008.

The amount outstanding under New 2nd Lien Credit Facility at March 31, 2008 was $110.9 million, net of a discount of $0.5 million, all of which was at the Eurodollar rate.

Repayment of a portion of New 2nd Lien Credit Facility. As described in Note A *Organization and nature of operations* , IPO proceeds in the amount of $86.6 million were used to repay a portion of the New 2nd Lien Credit Facility on August 9, 2007. Subsequent to such repayment the outstanding balance, net of remaining original issue discount, as of August 9, 2007, was $112.4 million. As set forth by this facility s credit agreement, effective on the consummation of the IPO, the interest margins on Eurodollar rate advances and prime rate advances increased to 425 basis points and 275 basis points, respectively, and remain in effect at March 31, 2008.

A pro rata portion of the deferred loan costs associated with the New 2nd Lien Credit Facility were written off to interest expense in August 2007 in the amount of approximately $1.0 million. Additionally, a pro rata portion of the unamortized original issue discount related to the New 2nd Lien Credit Facility was written off to interest expense in

August 2007 in the amount of approximately $0.4 million.

Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at March 31, 2008 for the nine months ended December 31, 2008 and the years ended December 31, 2009, 2010, 2011, 2012 and 2013 and thereafter, are as follows:

(in thousands)

2008	$ 1,500
2009	2,000
2010	192,000
2011	2,000
2012	103,900
Total	$ 301,400

Note K. ***Commitments and contingencies***

Daywork drilling contract commitments. The Company signed a daywork drilling contract with a drilling contractor on July 20, 2006, that provided the Company exclusive use of one rig with an operating day rate of $15,500 for a term that commenced on August 1, 2006 and ended on June 15, 2007. During February 2007, management decided to stack this rig due to budget modifications. The Company incurred contract drilling fees of approximately $1,296,000 related to this stacked rig during the year ended December 31, 2007. These costs were minimized as the drilling contractor secured work for the rig and refunded the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer.

The Company signed a new daywork drilling contract with the drilling contractor on June 26, 2007, that provides the Company exclusive use of one rig for a term that commenced on July 3, 2007 and ends on January 3, 2008. The Company may direct the rig to locations within the Permian Basin region as needed. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that the drilling contractor is liable for its employees, subcontractors and invitees. In addition, the drilling contractor is responsible for pollution or contamination from their equipment. The drilling contractor will release the Company of any liability for negligence of any party in connection with the drilling contractor. The operating day rate is $14,000. The operating day rate can be revised to reflect changes in costs incurred by the drilling contractor for labor and/or fuel. The contract allows an early termination by the Company with at least a thirty day notice and a payment of the lump sum termination amount equal to the current operating day rate less $6,000, multiplied by the days remaining through the end of the contract term. However, if the drilling contractor secures work for the subject rig with a new customer prior to the end of the contract term, drilling contractor will rebate the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer. Beginning on January 4, 2008, this contract was extended through July 31, 2008. The amended contract changed the operating day rate from $14,000 to $13,250. Beginning on March 12, 2008, this contract was amended to change the operating day rate from $13,250 to $12,850.

The Company signed daywork drilling contracts with Silver Oak Drilling, LLC (Silver Oak), an affiliate of the Chase Group, on August 1, 2006, that provide the Company use of four drilling rigs for a term that commenced on August 1, 2006 and ended on July 31, 2007. The Company could direct the rig to locations located in New Mexico as needed. If the Company moved the rig out of certain New Mexico counties specified in the contract, all effective daywork rates will be increased by an additional $2,000 per day. The Company was solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak was liable for its employees, subcontractors and invitees. In addition, Silver Oak was responsible for pollution or contamination from their equipment. Silver Oak released the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate was $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate could be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s personnel needed. Under the contracts, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contracts, Silver Oak had a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they were released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company would then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company released the rigs, the Company, with 20 days notice, could withdraw its release and reactivate the contract for the remainder of the term to the extent the rig had not been committed to a third party in mitigation of the Company s damages. During February 2007, management decided to stack these four rigs due to budget modifications. The Company incurred contract drilling fees of approximately $2,973,000 related to these stacked rigs during the year ended December 31, 2007, based on the drilling contracts described above. As of April 1, 2007, the Company began to utilize all four rigs, in order to proceed with its 2007 drilling budget.

The Company signed new daywork drilling contracts with Silver Oak on June 19, 2007, that provides the Company use of four drilling rigs for a term that commenced on August 1, 2007 and are in effect until drilling operations are completed on specified wells or for a term of one year. If any well commenced during the term of the contract is drilling at the expiration of the one year primary term, drilling will continue under the terms of the contract until drilling operations for that well have been completed. The Company may direct the rig to locations located in New Mexico as needed. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak is liable for its employees, subcontractors and invitees. In addition, Silver Oak is responsible for pollution or contamination from their equipment. Silver Oak will release the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate is $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate can be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s personnel needed. Under the contract, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contract, Silver Oak has a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they are released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company will then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company releases the rigs, the Company, with 20 days notice, may withdraw its release and reactivate the contracts for the remainder of the term to the extent the subject rig has not been committed to a third party in mitigation of damages.

Note L. *Income taxes*

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109 Accounting for Income Taxes . The Company and its subsidiaries file federal corporate income tax returns on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by United States federal and state taxing authorities. In determining the interim period income tax provision, the Company utilizes an estimated annual effective tax rate.

The Company adopted the provisions of FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes (FIN No. 48) an interpretation of FASB Statement No. 109 Accounting for Income Taxes, on January 1, 2007. At the time of adoption and as of March 31, 2008, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 through 2007 remain subject to examination by major tax jurisdictions.

The FASB issued FIN No. 48-1, Definition of Settlement in FASB Interpretation No. 48, to clarify when a tax position is effectively settled. This guidance is important in determining the proper timing for recognizing tax benefits and applying the new information relevant to the technical merits of a tax position obtained during a tax authority examination. FIN No. 48-1 provides criteria to determine whether a tax position is effectively settled after completion of a tax authority examination, even if the potential legal obligation remains under the statute of limitations. The Company s adoption of this pronouncement did not have a significant effect on its financial statements.

The Company s provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses.

Note M. *Related parties*

Contract Operator Agreement and Transition Services Agreement. On February 27, 2006, the Company signed a Contract Operator Agreement with Mack Energy Corporation (MEC), an affiliate of the Chase Group, whereby the Company engaged MEC as contract operator to provide certain services with respect to the Chase Group Properties. The initial term of the Contract Operator Agreement was 5 years commencing on March 1, 2006 and ending on February 28, 2011. The Company and MEC entered into a Transition Services Agreement on April 23, 2007, which terminated the Contract Operator Agreement and under which MEC continued to provide certain field level operating services on the Chase Group Properties. Under the Transition Services Agreement, MEC provided field level services, including pumping, well service oversight and supervision and certain equipment for workover and recompletion services, at costs prevailing in the area of the subject properties, but not to exceed charges for comparable services by and among MEC and its affiliates. MEC performed substantially similar services on behalf of the Company under the prior Contract Operator Agreement prior to its termination. In accordance with its terms, the Transition Services Agreement was terminated automatically by its terms on August 7, 2007 upon the Company s completion of the IPO. Upon termination, the Company s employees along with third party contractors assumed the operation of the subject properties.

The Company incurred charges from MEC of approximately $1.5 million for the three months ended March 31, 2008.

The Company incurred charges from MEC of approximately $5.1 million for the three months ended March 31, 2007, for services rendered under the Contract Operator Agreement.

At March 31, 2008, the Company had outstanding invoices payable to MEC of approximately $0.1 million which are reflected in

Accounts payable related parties in the accompanying consolidated balance sheet.

At December 31, 2007, the Company had outstanding invoices payable to MEC of approximately $0.4 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

Other related party transactions. The Company also has engaged in transactions with certain other affiliates of the Chase Group, including Silver Oak, an oilfield services company, a supply company, a drilling fluids supply company, a pipe and tubing supplier, a fixed base operator of aircraft services and a software company.

The Company incurred charges from these related party vendors of approximately $15.1 million and $12.5 million for the three months ended March 31, 2008 and 2007, respectively, for services rendered.

At March 31, 2008, the Company had outstanding invoices payable to the other related party vendors identified above of approximately $0.1 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheets.

At December 31, 2007, the Company had outstanding invoices payable to the other related party vendors mentioned above of approximately $1.7 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

Overriding royalty and royalty interests. Certain members of the Chase Group own overriding royalty interests in certain of the Chase Group Properties. The amount paid attributable to such interests was approximately $784,000 and $354,000 for the three months ended March 31, 2008 and 2007, respectively. The Company owed these owners royalty payments of approximately $288,000 and $315,000 as of March 31, 2008 and December 31, 2007, respectively.

Royalties are paid on certain properties located in Andrews County, Texas to a partnership of which one of the Company s directors is the general partner, and who also owns a 3.5% partnership interest. The Company paid this partnership approximately $83,000 and $23,000 for the three months ended March 31, 2008 and 2007, respectively. The Company owed this partnership royalty payments of approximately $25,000 and $29,000 as of March 31, 2008 and December 31, 2007, respectively.

In April 2005, the Company acquired certain working interests in 46,861 gross (26,908 net) acres located in Culberson County, Texas from an entity partially owned by a person who became an executive officer of the Company immediately following such acquisition. In connection with this acquisition, such entity retained a 2% overriding royalty interest in the acquired properties, which overriding royalty interest later became owned equally by such officer and a non-officer employee of the Company. During the three months ended March 31, 2008 and 2007, no payments were made related to this overriding royalty interest. Effective March 31, 2008, the referenced executive officer resigned from the Company.

Prospect participation. Subsequent to the closing of the Combination, the Company acquired working interests from Caza in certain lands in New Mexico in which Caza owns an interest.

There were no amounts paid to Caza during the three months ended March 31, 2008 for these interests. The Company paid Caza approximately $3,000 for the three months ended March 31, 2007, for delay rentals which are reflected in *Unproved properties* in the accompanying consolidated balance sheet at December 31, 2007.

At March 31, 2008 and December 31, 2007, the Company had no outstanding invoices owed to Caza.

Note N. *Net income per share*

Basic net income per share is computed by dividing net income applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period. As discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes* , agreements to sell stock to the Officers and certain employees subject to Purchase Notes are accounted for as options (Bundled Capital Options and Capital Options , respectively). As a result, Bundled Capital Options and Capital Options are excluded from the weighted average number of common shares treated as outstanding during each period until the Purchase Notes are paid in full, thus exercising the options.

The computation of diluted income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. These amounts include unexercised Bundled Capital Options, Capital Options, stock options (as issued under the 2004 Stock Option

Plan of CEHC and the Plan, both as described in Note H *Stock incentive plan*) and restricted stock. Potentially dilutive effects are calculated using the treasury stock method.

Table of Contents

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three months ended March 31, 2008 and 2007:

(in thousands)	Three months ended March 31, 2008	2007
Weighted average common shares outstanding:		
Basic	75,473	54,936
Dilutive Bundled Capital Options		2,729
Dilutive Capital Options	23	247
Dilutive common stock options	1,156	847
Dilutive restrictive stock	234	81
Diluted	76,886	58,840

Since the Company had net income applicable to common shareholders, the effects of all potentially dilutive securities including Bundled Capital Options, Capital Options, stock options and unvested restricted stock were considered in the computation of diluted earnings per share. Because the exercise prices of certain stock options were greater than the average market price of the common shares and would be anti-dilutive, stock options to purchase 450,000 of common stock were outstanding but not included in the computations of diluted income per share from continuing operations for the three months ended March 31, 2007.

Note O. ***Supplementary information***

Capitalized costs

(in thousands)	March 31, 2008	December 31, 2007
Oil and gas properties:		
Proved	$1,350,487	$1,303,665
Unproved	257,100	251,353
Less accumulated depletion	(188,051)	(167,109)
Net capitalized costs for oil and gas properties	$1,419,536	$1,387,909

Costs incurred for oil and gas producing activities

(in thousands)	Three months ended March 31, 2008	2007
Property acquisition costs:		
Proved	$ 105	$
Unproved	762	789
Exploration	29,565	11,707
Development	25,653	15,301
Capitalized asset retirement obligations and revisions	(775)	(367)

Total costs incurred for oil and gas properties	$55,310	$27,430

Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included in our Annual Report on Form 10-K for the year ended December 31, 2007.

Statements in our discussion may be forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause future production, revenue and expenses to differ materially from our expectations.

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of producing oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We have also acquired significant acreage positions in unconventional emerging resource plays located in the Permian Basin of Southeast New Mexico, the Central Basin Platform and the Western Delaware Basin of West Texas, the Williston Basin in North Dakota and the Arkoma Basin in Arkansas, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies. Crude oil comprised 59% of our 546.0 Bcfe of estimated net proved reserves as of December 31, 2007, and 60% of our 30.1 Bcfe of production for the year ended December 31, 2007. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 90% of our PV-10 and 50% of our 2,067 wells as of December 31, 2007. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

Recent Events

During the first quarter of 2008, we experienced short-term interruptions in our production on the Shelf Properties in New Mexico due to operational problems with a natural gas processing plant. There were a total of 10 days of curtailment during the first quarter, and approximately 100 MMcfe of our production was curtailed during this period.

Additionally, on April 7, 2008, a natural gas processing plant through which we process and sell a portion of the production from our Shelf Properties in New Mexico was curtailed for its annual routine maintenance. The plant became fully operational on April 19, 2008, and we began restoring production from all of our properties that had been affected. Approximately 450 MMcfe of our production was shut-in as a result of this plant shut-down.

Table of Contents

Results of operations of Concho Resources Inc.

The following table presents selected financial and operating information of Concho Resources Inc. for the three months ended March 31, 2008 and 2007:

	Three months ended March 31,	
	2008	2007
(in thousands, except price data)	(unaudited)	
Oil sales	$ 75,818	$ 39,371
Natural gas sales	30,893	20,975
Total operating revenues	106,711	60,346
Operating costs and expenses	48,205	41,938
Loss on derivatives not designated as hedges	17,178	
Interest, net and other revenue	4,595	10,410
Income before income taxes	36,733	7,998
Income tax expense	(14,368)	(3,375)
Net income	$ 22,365	$ 4,623
Production volumes:		
Oil (MBbl)	887	709
Natural gas (MMcf)	3,105	2,952
Natural gas equivalent (MMcfe)	8,427	7,206
Average prices:		
Oil, without hedges ($/Bbl)	$ 93.60	$ 54.09
Oil, with hedges ($/Bbl)	$ 85.48	$ 55.54
Natural gas, without hedges ($/Mcf)	$ 10.05	$ 7.06
Natural gas, with hedges ($/Mcf)	$ 9.95	$ 7.10
Natural gas equivalent, without hedges ($/Mcfe)	$ 13.55	$ 8.21
Natural gas equivalent, with hedges ($/Mcfe)	$ 12.66	$ 8.37

Bbl Barrel
MBbl Thousand Barrels
Mcf Thousand cubic feet
MMcf Million cubic feet
Mcfe Thousand cubic feet of natural gas equivalent (computed on an energy equivalent basis

of one Bbl equals six Mcf)
MMcfe Million cubic feet of natural gas equivalent (computed on an energy equivalent basis of one Bbl equals six Mcf)

Table of Contents

Three months ended March 31, 2008, compared to three months ended March 31, 2007

Oil and gas revenues. Revenue from oil and gas operations was $106.71 million for the three months ended March 31, 2008, an increase of $46.36 million (77%) from $60.35 million for the three months ended March 31, 2007. This increase was primarily because of increased production due to successful drilling efforts during 2007 coupled with substantial increases in realized oil and gas prices. In addition:

average realized oil prices (after giving effect to hedging activities) were $85.48 per Bbl during the three months ended March 31, 2008, an increase of 54% from $55.54 per Bbl during the three months ended March 31, 2007;

total oil production was 887 MBbl for the three months ended March 31, 2008, an increase of 178 MBbl (25%) from 709 MBbl for the three months ended March 31, 2007;

average realized natural gas prices (after giving effect to hedging activities) were $9.95 per Mcf during the three months ended March 31, 2008, an increase of 40% from $7.10 per Mcf during the three months ended March 31, 2007;

total natural gas production was 3,105 MMcf for the three months ended March 31, 2008, an increase of 153 MMcf (5%) from 2,952 MMcf for the three months ended March 31, 2007;

average realized natural gas equivalent prices (after giving effect to hedging activities) were $12.66 per Mcfe during the three months ended March 31, 2008, an increase of 51% from $8.37 per Mcfe during the three months ended March 31, 2007; and

total production was 8,427 MMcfe for the three months ended March 31, 2008, an increase of 1,221 MMcfe (17%) from 7,206 MMcfe for the three months ended March 31, 2007.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. Following is a summary of the effects of commodity hedges for the three months ended March 31, 2008 and 2007:

	Crude Oil Hedges Three months ended March 31,		Natural Gas Hedges Three months ended March 31,	
	2008 (unaudited)	2007 (unaudited)	2008 (unaudited)	2007 (unaudited)
Hedging revenue increase (decrease)	$ (7,206,000)	$ 1,027,000	$ (296,000)	$ 138,000
Hedged volumes (Bbls and MMBtus, respectively)	236,600	265,500	1,228,500	1,505,100
Hedged revenue increase (decrease) per hedged volume	$ (30.46)	$ 3.87	$ (0.24)	$ 0.09

During the three months ended March 31, 2008, our commodity price hedges decreased oil revenues by $7.21 million ($8.12 per Bbl). During the three months ended March 31, 2007, our commodity price hedges increased oil revenues by $1.03 million ($1.45 per Bbl). The effect of the commodity price hedges in decreasing oil revenues during the three months ended March 31, 2008 compared to their effect of increasing oil revenues during the three months ended March 31, 2007 was the result of (1) a higher average market price of NYMEX crude oil of $97.68 per Bbl in 2008 as compared to $58.33 per Bbl in 2007 and (2) the greater price difference between NYMEX and the weighted average hedge price in 2008 as compared to 2007, partially offset by a lower amount of hedged volumes of 236,600 Bbls in 2008 as compared to 265,500 Bbls in 2007.

During the three months ended March 31, 2008, our commodity price hedges decreased gas revenues by $0.30 million ($0.10 per Mcf). During the three months ended March 31, 2007, our commodity price hedges increased gas revenues by $0.14 million ($0.05 per Mcf). The effect of the commodity price hedges in decreasing gas revenues during the three months ended March 31, 2008 compared to their effect of increasing gas revenues during the three months ended March 31, 2007 was the result of (1) a higher average market reference price of natural gas of $7.30 per

MMBtu for settlements in 2008 as compared to $6.32 per MMBtu for settlements in 2007 and (2) the greater price difference between market reference price of natural gas and the weighted average hedge price for settlements in 2008 as compared to settlements in 2007, partially offset by a lower amount of hedged volumes of 1,228,500 MMBtus in 2008 as compared to 1,505,100 MMBtus in 2007.

Production expenses. Production expenses (including production taxes) were $16.90 million ($2.00 per Mcfe) for the three months ended March 31, 2008, an increase of $4.95 million (41%) from $11.95 million ($1.66 per Mcfe) for the three months ended March 31, 2007. The increase in production expenses is due to: (1) production expenses associated with new wells that were successfully completed in 2008 as a result of our drilling activities and (2) an increase in production taxes as discussed below. Lease operating expenses and workover costs comprised approximately 46% and 61% of production expenses for the three months ended March 31, 2008 and 2007, respectively. These costs per unit of production were $0.93 per Mcfe during the three months ended March 31, 2008, a decrease of 8% from $1.01 per Mcfe during the three months ended March 31, 2007. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 6% and 9% of lease operating expenses for the three months ended March 31, 2008 and 2007, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 54% and 39% of production expenses during the three months ended March 31, 2008 and 2007, respectively. Production taxes per unit of production were $1.08 per Mcfe during the three months ended March 31, 2008, an increase of 66% from $0.65 per Mcfe during the three months ended March 31, 2007. This increase was primarily due to an increase in average natural gas equivalent prices we received.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the three months ended March 31, 2008 and 2007:

	Three months ended March 31,	
(in thousands)	**2008 (unaudited)**	**2007 (unaudited)**
Geological and geophysical	$1,893	$ 399
Exploratory dry holes	18	30
Leasehold abandonments and other	830	12
Total exploration and abandonments	$2,741	$ 441

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the three months ended March 31, 2008 was $1.89 million, an increase of $1.49 million from $0.40 million for the three months ended March 31, 2007. This increase is primarily attributable to a comprehensive seismic survey on our Shelf Properties which was initiated in December 2007.

For the three months ended March 31, 2008, we recorded $0.83 million of leasehold abandonments, which are primarily related to prospects in Chaves and Eddy Counties, New Mexico and Andrews County, Texas. We had minimal leasehold abandonments during the three months ended March 31, 2007.

Depreciation and depletion expense. Depreciation and depletion expense was $21.28 million ($2.53 per Mcfe) for the three months ended March 31, 2008, an increase of $1.86 million from $19.42 million ($2.70 per Mcfe) for the three months ended March 31, 2007. The increase in depreciation and depletion expense was primarily due to capitalized costs associated with new wells that were successfully completed in 2007 and 2008 as a result of our drilling activities. The decrease in depreciation and depletion expense per Mcfe was primarily due to an increase in proved oil and natural gas reserves as a result of our successful development and exploratory drilling program as well as an increase of commodity prices utilized for the reserve estimates. The crude oil price utilized for the reserve estimate was $98.00 for the three months ended March 31, 2008, an increase of $35.50 (57%) from $62.50 for the three months ended March 31, 2007. The natural gas price utilized for the reserve estimate was $9.37 for the three months ended March 31, 2008, an increase of $2.03 (28%) from $7.34 for the three months ended March 31, 2007.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during the three months ended March 31, 2008, we recognized a non-cash charge against earnings of $0.16 million, which was comprised primarily of a prospect located in Eddy County, New Mexico. For the three months ended March 31, 2007, we recognized a non-cash charge against earnings of $1.11 million, 46% of which related to wells located in Eddy County, New Mexico; 35% of which related to a well located in Mountrail County, North Dakota; 14% of which related to wells drilled in Victoria County, Texas and 5% of which related to multiple immaterial wells drilled in various counties in Texas.

Contract drilling fees stacked rigs. As discussed in our Annual Report on Form 10-K for the year ended December 31, 2007, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the three months ended March 31, 2007 of approximately $3.35 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. These costs were minimized during the first six months of 2007 as one contractor secured work for a rig for 71 days during that period and charged us only the difference between the then-current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

General and administrative expenses. General and administrative expenses were $7.68 million ($0.91 per Mcfe) for the three months ended March 31, 2008, an increase of $3.39 million (79%) from $4.29 million ($0.60 per Mcfe) for the three months ended March 31, 2007. Included in general and administrative expense was non-cash stock-based compensation of $1.30 million during the three months ended March 31, 2008 and $0.83 million during the three months ended March 31, 2007. General and administrative expenses, excluding non-cash stock-based compensation, (Net general expense) were $6.38 million ($0.76 per Mcfe) for the three months ended March 31, 2008, an increase of $2.92 million (84%) from $3.46 million ($0.48 per Mcfe) for the three months ended March 31, 2007. The increase in Net general expenses during the three months ended March 31, 2008 was primarily due to an increase in the number of employees and related personnel expenses.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $0.24 million and $0.41 million during the three months ended March 31, 2008 and 2007, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Loss on derivatives not designated as cash flow hedges. As explained in *Hedging activities*, during the three months ended September 30, 2007, we determined that all of our natural gas commodity contracts no longer qualified as hedges under the requirements of SFAS No. 133. If the hedge is no longer highly effective, according to SFAS No. 133, an entity shall discontinue hedge accounting for an existing hedge, prospectively and during the period the hedges became ineffective. In addition, for our new derivative contracts entered into after August 2007, we chose not to designate any of these contracts as cash flow hedges. As a result, any changes in fair value must be recorded in earnings under *Loss on derivatives not designated as hedges* and any related cash settlements are recorded to *Loss on derivatives not designated as hedges* . For the three months ended March 31, 2008, the related cash settlement payments for derivative instruments not designated as cash flow hedges was approximately $3.99 million. The non-cash mark-to-market adjustment for other derivative instruments not designated as cash flow hedges was a loss of $13.19 million.

Interest expense. Interest expense was $5.62 million for the three months ended March 31, 2008, a decrease of $5.06 million from $10.68 million for the three months ended March 31, 2007. The weighted average interest rate for the three months ended March 31, 2008 and 2007 was 6.7% and 7.9%, respectively. The weighted average debt balance during the three months ended March 31, 2008 and 2007 was approximately $324.47 million and $496.43 million, respectively. The decrease in weighted average debt balance during the three months ended March 31, 2008 was due to the partial prepayment in August 2007 of $86.60 million on the New 2nd Lien Credit Facility and the repayment in August 2007 of $86.60 million on the 1st Lien Credit Facility as well as partial prepayment in March 2008 on the 1st Lien Credit Facility utilizing cash from operations. The decrease in interest expense is due to a decrease in the weighted average interest rate and the decrease in the weighted average debt. In March 2007, we reduced the 1st Lien Credit Facility borrowing base by $100.00 million, or 21%, resulting in accelerated deferred loan cost amortization of $0.77 million, and the full repayment of the 2nd Lien Credit Facility resulting in accelerated deferred loan cost amortization of $0.43 million.

Income tax provisions. We recorded income tax expense of $14.37 million and $3.38 million for the three months ended March 31, 2008 and 2007, respectively. The effective income tax rate for the three months ended March 31, 2008 and 2007 was 39.1% and 42.2%, respectively.

We had a net deferred tax liability of $260.29 million and $245.57 million at March 31, 2008 and December 31, 2007, respectively. The net liability balance is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006. The net change is due to 2008 intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principles in the United States of America, partially offset by an increase in deferred hedge losses.

Liquidity and capital resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facilities. We believe that funds from operating cash flows and our bank credit facilities should be sufficient to meet both our short-term working capital requirements and our 2008 exploration and development budget.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $69.81 million and $31.05 million for the three months ended March 31, 2008 and 2007, respectively. The increase in operating cash flows during the three months ended March 31, 2008 over 2007 was principally due to increases in our oil and gas production as a result of our exploration and development program and increases in average realized oil and natural gas prices.

Cash Flow Used in Investing Activities

During the three months ended March 31, 2008 and 2007, we invested $54.34 million and $36.56 million, respectively, for additions to, and acquisitions of, oil and gas properties, inclusive of dry hole costs. Cash flows used in investing activities were substantially higher during the three months ended March 31, 2008, primarily due to increased drilling activity in 2008. In order to preserve liquidity, we reduced our drilling activities and curtailed capital expenditures during the three months ended March 31, 2007, until we were able to complete our second lien term loan facility in March 2007.

Cash Flow from Financing Activities

Net cash used in financing activities was $27.24 million for the three months ended March 31, 2008 and net cash provided by financing activities was $6.97 million for the three months ended March 31, 2007. During the three months ended March 31, 2008, we reduced our outstanding balance by $26.00 million on our 1st Lien Credit Facility utilizing cash from operations. In March 2007, we entered into a $200.00 million second lien term loan facility. The proceeds were principally used to repay the outstanding balance under our prior term loan facility and to reduce the outstanding balance under our 1st Lien Credit Facility.

Bank Credit Facilities

We have two separate bank credit facilities. The first is our credit facility agreement, dated February 24, 2006, with JPMorgan Chase Bank, N.A. as the administrative agent for a group of lenders that provides a revolving line of credit having a total commitment of $475.00 million, which we refer to as our 1st Lien Credit Facility. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of the total commitment of $475.00 million or the borrowing base established by the lenders. Various amendments have redetermined the borrowing base under the 1st Lien Credit Facility, which was $425.00 million as of March 31, 2008. During 2007, the outstanding balance on our 1st Lien Credit Facility was reduced by $239.70 million from $455.70 million at December 31, 2006 to $216.00 million at December 31, 2007. This reduction is primarily the result of repayments we made with net proceeds of $154.00 million from our New 2nd Lien Credit Facility in March 2007 and the proceeds of $86.50 million from the IPO in August 2007.

The second bank credit facility is our term loan agreement, dated March 27, 2007, with Bank of America, N.A., as the administrative agent for the other lenders thereunder, that provides a five year term loan in the amount of $200.0 million, the New 2nd Lien Credit Facility. Upon execution of the New 2nd Lien Credit Facility, we funded the full amount under that facility and received net proceeds of $199.00 million to repay the $39.80 million outstanding under our 2nd Lien Credit Facility, to reduce the outstanding balance under our 1st Lien Credit Facility by $154.00 million and the remaining $5.20 million to pay loan fees, accrued interest and for general corporate purposes. We used net proceeds of approximately $173.00 million from our initial public offering that was completed in August 2007 to retire outstanding borrowings under our New 2nd Lien Credit Facility totaling $86.50 million and to retire outstanding borrowings under our 1st Lien Credit Facility totaling $86.50 million.

1st Lien Credit Facility. The 1st Lien Credit Facility allows us to borrow, repay and reborrow amounts available under the borrowing base. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base under our 1st Lien Credit Facility is re-determined at least semi-annually. The 1st Lien Credit Facility matures on February 24, 2010, and borrowings bear interest, payable quarterly, at our option, at (1) a rate (as defined and further described in our revolving credit facility) per annum equal to a Eurodollar Rate (which is substantially the same as the London Interbank Offered Rate) for one, two, three or six months as offered by the lead bank under our 1st Lien Credit Facility, plus an applicable margin ranging from 100 to 225 basis points, or (2) such bank s Prime Rate, plus an applicable margin ranging from 0 to 125 basis points, dependent in each case upon the percentage of our available borrowing base then utilized. Our 1st Lien Credit Facility bore interest at 3.54% per annum as of March 31, 2008. We pay quarterly commitment fees under our 1st Lien Credit

Facility on the unused portion of the available borrowing base ranging from 25 to 50 basis points, dependent upon the percentage of our available borrowing base then utilized.

Borrowings under our 1st Lien Credit Facility are secured by a first lien on substantially all of our assets and properties. Our 1st Lien Credit Facility also contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers involving our company, incur liens and engage in certain other transactions without the prior consent of the lenders. The 1st Lien Credit Facility also requires us to maintain certain ratios as defined and further described in our 1st Lien Credit Facility agreement, including a current ratio of not less than 1.0 to 1.0 and a maximum leverage ratio (generally defined as the ratio of total funded debt to a defined measure of cash flow) of no greater than 4.0 to 1.0. In addition, at the inception of the 1st Lien Credit Facility, we had a one-time requirement to enter into hedging agreements (as defined in our 1st Lien Credit Facility agreement, but not necessarily accounted for as cash flow hedges in our financial statements) with respect to not less than 75% of our forecasted production through December 31, 2008, that was attributable to our proved developed producing reserves estimated as of December 31, 2005. As of March 31, 2008, we were in compliance with all such covenants.

New 2nd Lien Credit Facility. The New 2nd Lien Credit Facility provides a $200.00 million term loan, which bears interest, at our option, at (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 425 basis points or (2) the prime rate, plus an applicable margin of 275 basis points. We have the option to select different interest periods, subject to availability, and interest is payable at the end of the interest period we select, though such interest payments must be made at least on a quarterly basis. We are required to repay $0.50 million of the outstanding balance on the last day of each calendar quarter, commencing June 30, 2007, until the remaining balance of the loan matures on March 27, 2012. Our New 2nd Lien Credit Facility bore interest at 6.85% per annum as of March 31, 2008. We have the right to prepay the outstanding balance at any time, provided, however, that we will incur a 2% prepayment penalty on any principal amount prepaid from March 27, 2008 until March 26, 2009 and a 1% prepayment penalty on any principal amount prepaid from March 27, 2009 until March 26, 2010.

Borrowings under the New 2nd Lien Credit Facility are secured by a second lien on the same assets as are securing our 1st Lien Credit Facility, and are subordinated to liens securing our 1st Lien Credit Facility. The New 2nd Lien Credit Facility also contains various restrictive financial covenants and compliance requirements that are similar to those contained in the 1st Lien Credit Facility, including the maintenance of certain financial ratios. As of March 31, 2008, we were in compliance with all such covenants.

Future Capital Expenditures and Commitments

On May 8, 2008, our board of directors approved an increase in our 2008 exploration and development budget in the amount of $67.8 million from $250.4 million to $318.2 million. Our 2008 capital budget is comprised of the following:

(in millions)	Original Budget	Revised Budget
Drilling and recompletion opportunities in our core operating area	$209.5	$239.8
Projects operated by third parties	14.3	14.2
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical	20.0	57.6
Maintenance capital in our core operating areas	6.6	6.6
Total 2008 exploration and development budget	$250.4	$318.2

We anticipate that this incremental $67.8 million in our 2008 exploration and development budget will be funded primarily by cash flow from operations.

Other than leasehold acreage and other property interests shown above, our 2008 exploration and development budget is exclusive of acquisitions. We do not have a specific acquisition budget since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and gas properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise or that otherwise have geologic characteristics that are similar to our existing properties.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations will be sufficient to satisfy our 2008 exploration and development budget; however, we could use our revolving credit facility to fund such expenditures. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. In addition, under certain circumstances we would consider increasing or reallocating our 2008 capital budget.

Commodity Derivatives and Hedging

On March 3, 2008, we entered into two crude oil price swaps to hedge an additional portion of our estimated crude oil production for calendar years 2008 and 2009. The contracts are for 1,400 Bbls per day for the remainder of 2008 (April through December) at a fixed price of $99.25 per Bbl, and 800 Bbls per day for calendar year 2009 at a fixed price of $98.35 per Bbl. We have not designated these derivative instruments as cash flow hedges. Mark-to-market adjustments related to these derivative instruments will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

On March 11, 2008, we entered into a natural gas price swap to hedge an additional portion of our estimated natural gas production for calendar year 2009. The contract is for 5,000 MMBtus per day with a fixed price of $8.44. We have not designated this derivative instrument as a cash flow hedge. Mark-to-market adjustments related to this derivative instrument will be recorded each period to *(Gain) loss on derivatives not designated as hedges.*

At March 31, 2008, we had oil price swaps that settle on a monthly basis covering future oil production from April 1, 2008 through December 31, 2009. The volumes are detailed in the table below. Subsequent to March 31, 2008, oil futures prices have continued to increase significantly and have continued to be at a level that exceeds the weighted average swap fixed price of $77.67. The average futures NYMEX price for the quarter ended March 31, 2008, was $97.68. As of May 2, 2008, the NYMEX futures price was $116.32. At this level, we will continue to remit the excess of the average monthly NYMEX futures price for each settlement period over the weighted average swap fixed price of $77.67. These payments could significantly affect our cash flow but the impact should be reduced by (1) payments made to counterparties to these contracts should be substantially offset by increased commodity prices received on the sale of our production and (2) only a portion of the total contract volume settles each month. The increase in oil prices, should it continue, will negatively affect the fair value of our commodities contracts as recorded in our balance sheet at March 31, 2008, during future periods and, consequently, our reported net income. Changes in the recorded fair value of certain of our commodity derivatives are marked to market through earnings and are likely to result in substantial charges to earnings for the decrease in the fair value of these contracts during the second quarter of 2008. If oil prices continue to increase, this negative effect on earnings could become more significant depending on the amount of increase in oil price. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our derivative contracts.

The table below provides the volumes and related data associated with our oil and natural gas derivatives as of March 31, 2008:

	Fair Market Value Asset / (Liability) (in thousands)	Aggregate remaining volume	Daily volume	Index price	Contract period
Cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	$ (22,779)	715,000	2,600	$ 67.50(a)	4/1/08 - 12/31/08
Cash flow hedges dedesignated:					
Natural gas (volumes in MMBtus):					
Price collar	(4,767)	3,712,500	13,500	$ 6.50-$9.35(b)	4/1/08 - 12/31/08
Derivatives not designated as cash flow hedges:					
Crude oil (volumes in Bbls):					
Price swap	(13,118)	935,000	3,400	$ 85.44(a)(c)	4/1/08 - 12/31/08
Price swap	(15,819)	1,022,000	2,800	$ 80.13(a)(c)	1/1/09 - 12/31/09

Natural gas (volumes in MMBtus):							
Price swap		(610)	1,825,000	5,000	$	8.44(b)	1/1/09 - 12/31/09
Net liability	$	(57,093)					

(a) The index prices for the oil price swaps are based on the NYMEX-West Texas Intermediate monthly average futures price.

(b) The index price for the natural gas price collar is based on the Inside FERC-El Paso Permian Basin first-of-the-month spot price.

(c) Amounts disclosed represent weighted average prices.

31

Valuation of Derivative Instruments

We measure our derivative instruments at fair value. Both realized and unrealized gains or losses from derivative instruments are reflected in *Oil and natural gas sales and Loss on derivatives not designated as hedges* in the consolidated statements of operations.

We adopted SFAS No. 157, Fair Value Measurements (SFAS No. 157), in the first quarter of 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

SFAS No. 157 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date, or an exit price. The degree of judgment utilized in measuring the fair value of derivative instruments generally correlates to the level of pricing observability. Derivative instruments with readily available active quoted prices or for which fair value can be measured from actively quoted prices in active markets generally have more pricing observability and less judgment utilized in measuring fair value. Conversely, derivative instruments rarely traded or not quoted have less observability and are measured at fair value using valuation models that require more judgment. Pricing observability is impacted by a number of factors, including the type of derivative instrument, whether the derivative instrument is new to the market and not yet established, the characteristics specific to the transaction and overall market conditions generally.

The overall valuation process for derivative instruments may include adjustments to valuations derived from pricing models. These adjustments may be made when, in management s judgment, either the size of the position in the derivative instrument or other features of the derivative instrument such as its complexity, or the market in which the derivative instrument is traded (such as counterparty, credit, concentration or liquidity) require that an adjustment be made to the value derived from the pricing models. An adjustment may be made if the sale of a derivative instrument is subject to sales restrictions that would result in a price less than the computed fair value measurement from a quoted market price. Additionally, an adjustment from the price derived from a model typically reflects management s judgment that other participants in the market for the derivative instrument being measured at fair value would also consider such an adjustment in pricing that same derivative instrument.

We have categorized our derivative instruments measured at fair value into a three-level classification in accordance with SFAS No. 157. Fair value measurements of derivative instruments that use quoted prices in active markets for identical assets or liabilities are generally categorized as Level 1, and fair value measurements of derivative instruments that have no direct observable levels are generally categorized as Level 3. The lowest level input that is significant to the fair value measurement of a derivative instrument is used to categorize the instrument and reflects the judgment of management. Derivative assets and liabilities presented at fair value in our consolidated balance sheet generally are categorized as follows:

Level 1 Inputs are unadjusted, quoted prices in active markets for identical, unrestricted assets or liabilities at the measurement date.

Level 2 Inputs (other than quoted prices included in Level I) are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument s anticipated life.

Generally, assets and liabilities carried at fair value included in this category are commodity price swaps.

Level 3 Inputs reflect management s best estimate of what market participants would use in pricing the asset or liability at the measurement date. Consideration is given to the risk inherent in the valuation technique and the risk inherent in the inputs to the model.

Generally, assets and liabilities carried at fair value included in this category are commodity price collars.

Derivative assets and liabilities presented at fair value and categorized as Level 3 are generally those that are marked to model using relevant empirical data to extrapolate an estimated fair value. The models inputs reflect assumptions that market participants would use in pricing the instrument in a current period transaction and outcomes from the models represent an exit price and expected future cash flows. Valuation models are calibrated to the market on a frequent basis.

The parameters and inputs are adjusted for assumptions about risk and current market conditions. Changes to inputs in valuation models are not changes to valuation methodologies; rather, the inputs are modified to reflect direct or indirect impacts on asset classes from changes in market conditions. Accordingly, results from valuation models in one period may not be indicative of future period measurements.

Table of Contents

The following table presents comparative metrics of the Company s Level 3 liabilities at March 31, 2008 and December 31, 2007:

(in thousands)	March 31, 2008	December 31, 2007
Level 3 derivative assets	$	$ 1,866
Less: Level 3 derivative liabilities	(4,767)	
Level 3 net derivative assets (liabilities)	$ (4,767)	$ 1,866
Total assets (liabilities)	$(726,560)	$1,508,229
Total derivative assets measured at fair value	$ 694	$ 1,866
Less: Total derivative liabilities measured at fair value	(57,787)	(46,931)
Net derivative assets (liabilities) measured at fair value	$ (57,093)	$ (45,065)
Level 3 derivative assets (liabilities) as a percent of total assets (liabilities)	1%	0%
Level 3 derivative assets (liabilities) as a percent of total derivative assets (liabilities) measured at fair value	8%	100%
Level 3 net derivative assets (liabilities) as a percent of net derivative assets (liabilities) measured at fair value	8%	4%

For a further discussion regarding the measurement of derivative instruments at fair value, see Note D *Fair Value Measurements,* to the consolidated financial statements.

Contractual obligations and commitments

We had the following material changes in our contractual obligations and commitments as of March 31, 2008:

		Payments due by period			
(in thousands)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Employment agreements with executive officers [(a)]	$2,719	$2,125	$594	$	$

(a) Represents amounts of cash compensation we are obligated to pay to our executive officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

Effective March 1, 2008, Messrs. Leach and Beal each received an annual pay increase of $100,000. An executive officer resigned as of March 31, 2008, and the Company will be obligated to pay such person 1/12th of his base salary for each month from April 2008 through March 2009 as consideration for such person s covenant not to compete with the Company in accordance with his employment agreement.

Off-balance sheet arrangements

Currently we do not have any off-balance sheet arrangements.

Critical accounting policies and practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

There have been no material changes in our critical accounting policies and procedures during the three months ended March 31, 2008. See our disclosure of critical accounting policies in the consolidated financial statements on our Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on March 28, 2007.

Recent accounting pronouncements

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, which will become effective in 2008. SFAS No. 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. We adopted this statement January 1, 2008 and did not elect the fair value option for any of its eligible financial instruments or other items. As such, the adoption had no impact on the consolidated financial statements.

In April 2007, the FASB issued FASB Staff Position FIN 39-1, Amendment of FASB Interpretation No. 39 (FIN No. 39-1). FIN No. 39-1 clarifies that a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement. FIN No. 39-1 is effective for financial statements issued for fiscal years beginning after November 15, 2007. Adoption of FIN No. 39-1 has not had a material impact on our consolidated financial statements.

In June 2007, the FASB ratified a consensus opinion reached by the Emerging Issues Task Force (EITF) on EITF Issue 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. EITF Issue 06-11 requires an employer to recognize tax benefits realized from dividend or dividend equivalents paid to employees for certain share-based payment awards as an increase to additional paid-in capital and include such amounts in the pool of excess tax benefits available to absorb future tax deficiencies on share-based payment awards. If an entity s estimate of forfeitures increases (or actual forfeitures exceed the entity s estimates), or if an award is no longer expected to vest, entities should reclassify the dividends or dividend equivalents paid on that award from retained earnings to compensation cost. However, the tax benefits from dividends that are reclassified from additional paid-in capital to the income statement are limited to the entity s pool of excess tax benefits available to absorb tax deficiencies on the date of reclassification. The consensus in EITF Issue 06-11 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2007. Retrospective application of EITF Issue 06-11 is not permitted. Early adoption is permitted; however, we did not adopt EITF Issue 06-11 until the required effective date of January 1, 2008. The adoption of EITF Issue 06-11 has not had a significant effect on our financial statements since we historically have accounted for the income tax benefits of dividends paid for share-based payment awards in the manner described in the consensus.

In December 2007, the FASB issued SFAS No. 141 (revised 2007), Business Combinations (SFAS No. 141(R)), which replaces FASB Statement No. 141. SFAS No. 141(R) establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non- controlling interest in the acquiree and the goodwill acquired. The Statement also establishes disclosure requirements that will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective for acquisitions that occur in an entity s fiscal year that begins after December 15, 2008, which will be our fiscal year 2009. The impact, if any, will depend on the nature and size of business combinations we consummate after the effective date.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51. SFAS No. 160 requires that accounting and reporting for minority interests will be recharacterized as noncontrolling interests and classified as a component of equity. SFAS No. 160 also establishes reporting requirements that provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations, but will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries or that deconsolidate a subsidiary. This statement is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008, which will be our fiscal year 2009. Based upon our March 31, 2008 balance sheet, the statement would have no impact.

Table of Contents

In December 2007, the SEC issued Staff Accounting Bulletin (SAB) No. 110, Share-Based Payment (SAB No. 110). SAB No. 110 amends SAB No. 107, Share-Based Payment, and allows for the continued use, under certain circumstances, of the simplified method in developing an estimate of the expected term on stock options accounted for under SFAS No. 123R, Share-Based Payment (revised 2004). SAB No. 110 is effective for stock options granted after December 31, 2007. We continued to use the simplified method in developing an estimate of the expected term on stock options granted in the first quarter of 2008. We do not have sufficient historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time our shares of common stock have been publicly traded.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities (SFAS No. 161), which amends and expands the disclosure requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to provide an enhanced understanding of an entity s use of derivative instruments, how they are accounted for under SFAS No. 133 and their effect on the entity s financial position, financial performance and cash flows. The provisions of SFAS No. 161 are effective as of January 1, 2009. We are currently evaluating the impact on our consolidated financial statements of adopting SFAS No. 161.

Cautionary statement regarding forward-looking statements

This report may contain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this quarterly report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this quarterly report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potent similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed in our Annual Report on Form 10-K for the year ended December 31, 2007, could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

§ business strategy;

§ estimated quantities of oil and natural gas reserves;

§ technology;

§ financial strategy;

§ oil and natural gas realized prices;

§ timing and amount of future production of oil and natural gas;

§ the amount, nature and timing of capital expenditures;

§ drilling of wells;

§ competition and government regulations;

§ marketing of oil and natural gas;

§ exploitation or property acquisitions;

§ costs of exploiting and developing our properties and conducting other operations;

§ general economic and business conditions;

§ cash flow and anticipated liquidity;

§ uncertainty regarding our future operating results; and

§ plans, objectives, expectations and intentions contained in this quarterly report that are not historical.

You should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this quarterly report. We do not undertake any obligation to release publicly any revisions to the forward-looking statements to reflect events or circumstances after the date of this quarterly report or to reflect the occurrence of unanticipated events except as required by law.

Although we believe that our plans, objectives, expectations and intentions reflected in or suggested by the forward-looking statements we make in this quarterly report are reasonable, we can give no assurance that they will be achieved. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Annual Report on Form 10-K for the year ended December 31, 2007, as well as with the consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments.

Hypothetical changes in interest rates and prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries, as described under Item 1. Business Marketing Arrangements in our Annual Report on Form 10-K for the year ended December 31, 2007. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future.

Commodity price risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of oil and natural gas we have entered into, and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management activities could have the effect of reducing our revenues, net income and the value of our common stock. As of March 31, 2008, the net unrealized loss on our commodity price risk management contracts was $57.1 million. An average increase in the commodity price of $1.00 per barrel of crude oil and $0.10 per Mcf for natural gas from the commodity prices as of March 31, 2008, would have resulted in an increase in the net unrealized loss on our commodity price risk management contracts, as reflected on our balance sheet as of March 31, 2008, of approximately $2.8 million.

At March 31, 2008, we had oil price swaps that settle on a monthly basis covering future oil production from April 1, 2008 through December 31, 2009. See Commodity Derivatives and Hedging. Subsequent to March 31, 2008, oil futures prices have continued to increase significantly and have continued to be at a level that exceeds the weighted average swap fixed price of $77.67. The average futures NYMEX price for the quarter ended March 31, 2008, was $97.68. As of May 2, 2008, the NYMEX futures price was $116.32. At this level, we will continue to remit the excess of the average monthly NYMEX futures price for each settlement period over the weighted average swap fixed price of $77.67. These payments could significantly affect our cash flow but the impact should be reduced by (1) payments made to counterparties to these contracts should be substantially offset by increased commodity prices received on the sale of our production and (2) only a portion of the total contract volume settles each month. The increase in oil prices, should it continue, will negatively affect the fair value of our commodities contracts as recorded in our balance sheet at March 31, 2008, during future periods and, consequently, our reported net income. Changes in the recorded fair value of certain of our commodity derivatives are marked to market through earnings and are likely to result in substantial charges to earnings for the decrease in the fair value of these contracts during the second quarter of 2008. If oil prices continue to increase, this negative effect on earnings could become more significant depending on the amount of increase in oil price. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our derivative contracts.

Interest rate risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our bank credit facilities, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. We had total indebtedness of $190.0 million outstanding under our revolving credit facility at March 31, 2008. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.9 million and a corresponding decrease in net income before income tax. As of March 31, 2008, we had $111.4 million of outstanding indebtedness under our 2nd Lien Credit Facility. The impact of a 1% increase in interest rates on this amount of debt under our second lien term loan facility would result in increased interest expense of approximately $1.1 million and a corresponding decrease in net income before income tax.

Table of Contents

Item 4. CONTROLS AND PROCEDURES

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a-15(e) under the Securities Exchange Act of 1934) as of the end of the period covered by this quarterly report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our Chief Executive Officer and Chief Financial Officer have concluded that, as of March 31, 2008, our disclosure controls and procedures were effective, in all material respects, to ensure that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms.

We have begun taking steps to comprehensively document and analyze our system of internal controls. We plan to continue this initiative as well as prepare for our first management report on internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act of 2002, prior to its applicability to us in connection with our filing of our Annual Report on Form 10-K for the year ending December 2008. In that regard, we have made and expect to continue to make changes in our internal controls over financial reporting. Although these changes may continue to improve our internal controls, there were no changes in our internal controls over financial reporting that occurred during the period covered by this Quarterly Report on Form 10-Q that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Amended and Restated Bylaws of Concho Resources Inc., as amended March 25, 2008 (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K on March 26, 2008, and incorporated herein by reference)
10.1	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on March 4, 2008, and incorporated herein by reference)
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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.

CONCHO RESOURCES INC.

Date: May 14, 2008

By /S/ Timothy A. Leach
Timothy A. Leach
Director, Chairman of the Board of Directors and Chief Executive Officer (Principal Executive Officer)

By /S/ Curt F. Kamradt
Curt F. Kamradt
Vice President, Chief Financial Officer and Treasurer
(Principal Financial and Accounting Officer)