CONCHO RESOURCES INC
Form 10-Q
August 06, 2009

Table of Contents

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 June 30, 2009

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 100 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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

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

Large accelerated filer þ Accelerated filer o Non-accelerated filer o 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 August 3, 2009: 85,521,179 shares.

TABLE OF CONTENTS

Table of Contents

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 (the Securities Act) and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act) 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 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 report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predi project and 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 in our Annual Report on Form 10-K for the year ended December 31, 2008 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, 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 and financial strategy;
- the estimated quantities of oil and natural gas reserves;
- our use of industry technology;
- our realized oil and natural gas prices;
- the timing and amount of the future production of our oil and natural gas;
- the amount, nature and timing of our capital expenditures;
- the drilling of our wells;
- our competition and government regulations;
- the marketing of our oil and natural gas;
- our exploitation activities or property acquisitions;
- the costs of exploiting and developing our properties and conducting other operations;
- general economic and business conditions;
- our cash flow and anticipated liquidity;
- uncertainty regarding our future operating results;
- our plans, objectives, expectations and intentions contained in this report that are not historical; and
- our ability to integrate acquisitions.

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

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Consolidated Financial Statements (Unaudited)

Table of Contents

Concho Resources Inc.
Consolidated Balance Sheets
Unaudited

(in thousands, except share and per share data)	June 30, 2009	December 31, 2008
Assets		
Current assets:		
Cash and cash equivalents	$ 3,081	$ 17,752
Accounts receivable, net of allowance for doubtful accounts:		
Oil and natural gas	58,430	48,793
Joint operations and other	73,992	92,833
Related parties	174	314
Derivative instruments	26,272	113,149
Prepaid costs and other	5,330	5,942
Total current assets	167,279	278,783
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	2,885,275	2,693,574
Accumulated depletion	(413,252)	(306,990)
Total oil and natural gas properties, net	2,472,023	2,386,584
Other property and equipment, net	15,143	14,820
Total property and equipment, net	2,487,166	2,401,404
Deferred loan costs, net	13,988	15,701
Inventory	27,158	19,956
Intangible asset, net operating rights	37,319	37,768
Noncurrent derivative instruments	31,438	61,157
Other assets	451	434
Total assets	$ 2,764,799	$ 2,815,203
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable:		
Trade	$ 15,837	$ 7,462
Related parties	1,352	312
Other current liabilities:		
Bank overdrafts	2,628	9,434
Revenue payable	31,262	22,286
Accrued and prepaid drilling costs	111,172	154,196
Derivative instruments	15,731	1,866
Deferred income taxes	3,300	37,205
Other current liabilities	38,149	38,057

Total current liabilities	219,431	270,818
Long-term debt	660,000	630,000
Noncurrent derivative instruments	17,656	
Deferred income taxes	565,217	573,763
Asset retirement obligations and other long-term liabilities	12,940	15,468
Commitments and contingencies (Note K)		
Stockholders equity:		
Common stock, $0.001 par value; 300,000,000 authorized; 85,529,591 and 84,828,824 shares issued at June 30, 2009 and December 31, 2008, respectively	86	85
Additional paid-in capital	1,020,060	1,009,025
Retained earnings	269,726	316,169
Treasury stock, at cost; 9,341 and 3,142 shares at June 30, 2009 and December 31, 2008, respectively	(317)	(125)
Total stockholders equity	1,289,555	1,325,154
Total liabilities and stockholders equity	$ 2,764,799	$ 2,815,203

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

1

Concho Resources Inc.
Consolidated Statements of Operations
Unaudited

(in thousands, except per share amounts)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Operating revenues:				
Oil sales	$ 101,511	$ 95,408	$ 166,485	$ 171,226
Natural gas sales	25,821	41,975	46,849	72,868
Total operating revenues	127,332	137,383	213,334	244,094
Operating costs and expenses:				
Oil and natural gas production	25,817	21,979	50,583	38,874
Exploration and abandonments	1,424	723	7,419	3,464
Depreciation, depletion and amortization	52,402	22,010	103,150	43,294
Accretion of discount on asset retirement obligations	301	148	579	301
Impairments of long-lived assets	4,499	53	8,555	69
General and administrative (including non-cash stock-based compensation of $2,188 and $1,730 for the three months ended June 30, 2009 and 2008, respectively, and $4,113 and $3,029 for the six months ended June 30, 2009 and 2008, respectively)	14,172	8,586	25,918	16,266
Bad debt expense		1,799		1,799
Ineffective portion of cash flow hedges		(356)		(920)
Loss on derivatives not designated as hedges	81,606	102,456	86,652	119,634
Total operating costs and expenses	180,221	157,398	282,856	222,781
Income (loss) from operations	(52,889)	(20,015)	(69,522)	21,313
Other income (expense):				
Interest expense	(6,200)	(3,885)	(10,570)	(9,500)
Other, net	180	311	(148)	1,331
Total other expense	(6,020)	(3,574)	(10,718)	(8,169)
Income (loss) before income taxes	(58,909)	(23,589)	(80,240)	13,144
Income tax (expense) benefit	25,691	9,169	33,797	(5,199)
Net income (loss)	$ (33,218)	$ (14,420)	$ (46,443)	$ 7,945
Basic earnings per share:				
Net income (loss) per share	$ (0.39)	$ (0.19)	$ (0.55)	$ 0.11
Weighted average shares used in basic earnings per share	84,799	75,665	84,665	75,569

Diluted earnings per share:				
Net income (loss) per share	$ (0.39)	$ (0.19)	$ (0.55)	$ 0.10
Weighted average shares used in diluted earnings per share	84,799	75,665	84,665	77,034

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

2

Table of Contents

Concho Resources Inc.
Consolidated Statement of Stockholders Equity
Unaudited

(in thousands)	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Total Stockholders Equity
BALANCE AT DECEMBER 31, 2008	84,829	$ 85	$ 1,009,025	$ 316,169	3	$ (125)	$ 1,325,154
Net loss				(46,443)			(46,443)
Stock options exercised	446	1	3,930				3,931
Stock-based compensation for restricted stock	257		2,200				2,200
Cancellation of restricted stock	(2)						
Stock-based compensation for stock options			1,913				1,913
Excess tax benefits related to stock-based compensation			2,992				2,992
Purchase of treasury stock					6	(192)	(192)
BALANCE AT JUNE 30, 2009	85,530	$ 86	$ 1,020,060	$ 269,726	9	$ (317)	$ 1,289,555

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

Concho Resources Inc.
Consolidated Statements of Cash Flows
Unaudited

(in thousands)	Six Months Ended June 30, 2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (46,443)	$ 7,945
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	103,150	43,294
Impairments of long-lived assets	8,555	69
Accretion of discount on asset retirement obligations	579	301
Exploration expense, including dry holes	6,294	1,147
Non-cash compensation expense	4,113	3,029
Bad debt expense		1,799
Deferred income taxes	(39,799)	4,504
(Gain) loss on sale of assets	191	(777)
Ineffective portion of cash flow hedges		(920)
Loss on derivatives not designated as hedges	86,652	119,634
Dedesignated cash flow hedges reclassified from accumulated other comprehensive income		222
Other non-cash items	1,686	558
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(18,401)	(12,003)
Prepaid costs and other	612	793
Inventory	(6,786)	(7,243)
Accounts payable	9,415	(10,209)
Revenue payable	8,976	7,718
Other current liabilities	(562)	3,087
Net cash provided by operating activities	118,232	162,948
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and natural gas properties	(223,283)	(122,757)
Additions to other property and equipment	(2,014)	(4,017)
Proceeds from the sale of oil and natural gas properties and other assets	1,004	1,034
Settlements received (paid) on derivatives not designated as hedges	61,465	(16,387)
Net cash used in investing activities	(162,828)	(142,127)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	211,650	13,000
Payments of long-term debt	(181,650)	(39,500)
Exercise of stock options	3,931	2,373
Excess tax benefit from stock-based compensation	2,992	2,146
Proceeds from repayment of employee notes		333
Payments for loan origination costs		(1,001)

Purchase of treasury stock	(192)	(125)
Bank overdrafts	(6,806)	3,245
Net cash provided by (used in) financing activities	29,925	(19,529)
Net increase (decrease) in cash and cash equivalents	(14,671)	1,292
Cash and cash equivalents at beginning of period	17,752	30,424
Cash and cash equivalents at end of period	$ 3,081	$ 31,716
SUPPLEMENTAL CASH FLOWS:		
Cash paid for interest and fees, net of $18 and $840 capitalized interest	$ 6,911	$ 9,918
Cash paid for income taxes	$ 4,232	$ 650

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

4

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

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

Concho Resources Inc. (the Company) is a Delaware corporation formed on February 22, 2006. The Company s principal business is the acquisition, development, exploitation and exploration of oil and natural gas properties in the Permian Basin region of Southeastern New Mexico and West Texas.

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

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

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties are determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, asset retirement obligations, fair value of derivative financial instruments, purchase price allocations for business and oil and natural gas property acquisitions and fair value of stock-based compensation.

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, 2008 is derived from audited consolidated financial statements. In the opinion of management, the accompanying consolidated financial statements reflect all adjustments necessary to present fairly the Company s financial position at June 30, 2009, its results of operations for the three and six months ended June 30, 2009 and 2008, and its cash flows for the six months ended June 30, 2009 and 2008. All such adjustments are of a normal recurring nature. In preparing the accompanying consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed or omitted from these consolidated financial statements. Accordingly, these consolidated 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, 2008.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of $14.0 million and $15.7 million, net of accumulated amortization of $6.6 million and $4.9 million, at June 30, 2009 and December 31, 2008, respectively.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Future amortization expense of deferred loan costs at June 30, 2009 is as follows:

(in thousands)	**Total**
Remaining 2009	$ 1,713
2010	3,426
2011	3,426
2012	3,426
2013	1,997
Total	$ 13,988

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition, see Note D. The gross operating rights of approximately $38.7 million, which have no residual value, are amortized over the estimated economic life of approximately 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. Amortization expense for the three and six months ended June 30, 2009 was approximately $0.4 million and $0.8 million, respectively. The following table reflects the estimated aggregate amortization expense at June 30, 2009 for each of the periods presented below:

(in thousands)	**Total**
Remaining 2009	$ 775
2010	1,550
2011	1,550
2012	1,550
2013	1,550
Thereafter	30,344
Total	$ 37,319

Oil and natural gas sales and imbalances. Oil and natural 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 natural gas sales, recognizing revenues based on the Company s share of actual proceeds from the oil and natural gas sold to purchasers. Oil and natural 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 from or payable to the other owners unless the imbalance has reached a level at which 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.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The following table reflects the Company s natural gas imbalance positions at June 30, 2009 and December 31, 2008 as well as amounts reflected in oil and natural gas production expense for the three and six months ended June 30, 2009 and 2008:

(dollars in thousands)	June 30, 2009	December 31, 2008
Natural gas imbalance receivable (included in other assets)	$ 423	$ 406
Undertake position (Mcf)	(94,102)	(90,321)
Natural gas imbalance liability (included in asset retirement obligations and other long-term liabilities)	$ 449	$ 472
Overtake position (Mcf)	79,408	85,698

	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Value of net overtake (undertake) arising during the period (increasing (reducing) oil and natural gas production expense)	$ 9	$ (133)	$ (40)	$ (137)
Net overtake (undertake) position arising during the period (Mcf)	1,697	(9,117)	(10,069)	(8,103)

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees totaled approximately $2.8 million and $0.3 million for the three months ended June 30, 2009 and 2008, respectively, and $5.4 million and $0.5 million for the six months ended June 30, 2009 and 2008, respectively.

Reclassifications. Certain prior period amounts have been reclassified to conform to the 2009 presentation. These reclassifications had no impact on net income (loss), total stockholders equity or cash flows.

Recent accounting pronouncements. In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), *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. SFAS No. 141(R) 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. The Company adopted SFAS No. 141(R) effective January 1, 2009. There has been no impact on the Company s consolidated financial statements, as it has not entered into any significant business combinations during 2009.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51* (SFAS No. 160). 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. The Company adopted SFAS No. 160 effective January 1, 2009, with no impact on the Company s consolidated financial statements.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161), which amends and expands the interim and annual disclosure requirements of 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 adopted SFAS No. 161 effective January 1, 2009, with no significant impact on the Company s consolidated financial statements, other than additional disclosures which are set forth below in Notes H and I.

In April 2008, the FASB issued FASB Staff Position (FSP) No. SFAS 142-3, *Determination of the Useful Life of Intangible Assets* (FSP SFAS No. 142-3). FSP SFAS No. 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). The intent of FSP SFAS No. 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R and other applicable accounting literature. FSP SFAS No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. The Company adopted FSP SFAS No. 142-3 effective January 1, 2009, with no significant impact on the Company s consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162), which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 arranges these sources of GAAP in a hierarchy for users to apply accordingly. This statement became effective for the Company on November 15, 2008. The adoption of SFAS No. 162 did not have a significant impact on the Company s consolidated financial statements. In June 2009, this statement was replaced with SFAS No. 168, *The FASB Accounting Standards Codification* (Codification) *and the Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 168). Once the Codification is in effect, all of its content will carry the same level of authority, effectively superseding SFAS No. 162. In other words, the GAAP hierarchy will be modified to include only two levels of GAAP: authoritative and non authoritative. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. The Company does not expect the adoption of SFAS No. 168 to have an impact on its consolidated financial statements.

In June 2008, the FASB issued FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 was effective for the Company on January 1, 2009. There was no impact on the Company s consolidated financial statements.

In April 2009, the FASB issued FSP SFAS No. 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies.* This FSP amends and clarifies SFAS No. 141(R) to address application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP is effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company has not made any acquisitions during 2009, and as such, the adoption of this statement on January 1, 2009 did not have a significant impact.

In April 2009, the FASB issued FSP SFAS No. 107-1 and APB Opinion No. 28-1, *Interim Disclosures about Fair Value of Financial Instrument* (FSP SFAS No. 107-1). This FSP amends FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments,* to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This FSP also amends APB Opinion No. 28, *Interim Financial Reporting,* to require those disclosures in summarized financial information at interim reporting periods. This FSP is effective for interim reporting periods ending after June 15, 2009. This FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, this FSP requires comparative disclosures only for periods ending after initial adoption. As of June 15, 2009, the Company adopted the provisions of FSP SFAS No. 107-1 related to the fair value of financial

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

instruments. The adoption of the provisions of FSP SFAS No. 107-1 did not have a material effect on the financial condition or results of operations of the Company. See Note H for additional disclosures required by FSP SFAS No. 107-1.

In April 2009, the FASB issued FSP SFAS No. 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP SFAS No. 157-4). This FSP:

Affirms that the objective of fair value when the market for an asset is not active is the price that would be received to sell the asset in an orderly transaction;

Clarifies and includes additional factors for determining whether there has been a significant decrease in market activity for an asset when the market for that asset is not active;

Eliminates the proposed presumption that all transactions are distressed (not orderly) unless proven otherwise. The FSP instead requires an entity to base its conclusion about whether a transaction was not orderly on the weight of the evidence;

Includes an example that provides additional explanation on estimating fair value when the market activity for an asset has declined significantly;

Requires an entity to disclose a change in valuation technique (and the related inputs) resulting from the application of the FSP and to quantify its effects, if practicable; and

Applies to all fair value measurements when appropriate.

FSP SFAS No. 157-4 must be applied prospectively and retrospective application is not permitted. FSP SFAS No. 157-4 is effective for interim and annual periods ending after June 15, 2009. As of June 15, 2009, the Company adopted the provisions of FSP SFAS No. 157-4 related to assets and liabilities that are measured at fair value on a recurring and nonrecurring basis. The adoption of the provisions of FSP SFAS No. 157-4 did not have a material effect on the financial condition or results of operations of the Company. See Note H for additional information regarding the Company s adoption of FSP SFAS No. 157-4.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS No. 165) which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. In particular, SFAS No. 165 sets forth:

The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;

The circumstances under which a reporting entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and

The disclosures that a reporting entity should make about events or transactions that occurred after the balance sheet date.

In accordance with this Statement, a reporting entity should apply the requirements to interim or annual financial periods ending after June 15, 2009. See Note P.

In June 2009, the FASB issued SFAS No. 166, *Accounting for Transfers of Financial Assets* (SFAS No. 166), which amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. This statement improves the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

flows; and a transferor s continuing involvement in transferred financial assets. SFAS No. 166 must be applied as of the beginning of a reporting entity s first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period and for interim and annual reporting periods thereafter. Earlier application is prohibited. SFAS No. 166 must be applied to transfers occurring on or after the effective date. The Company does not expect the adoption of SFAS No. 166 to have an impact on its consolidated financial statements.

Recent developments in reserves reporting. In December 2008, the United States Securities and Exchange Commission (the SEC) released Final Rule, *Modernization of Oil and Gas Reporting* (the Reserve Ruling). The Reserve Ruling revises oil and gas reporting disclosures. The Reserve Ruling permits the use of new technologies to determine proved reserves estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Reserve Ruling will also allow, but not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Reserve Ruling becomes effective for fiscal years ending on or after December 31, 2009. The Company is currently assessing the impact that adoption of the provisions of the Reserve Ruling will have on its financial position, results of operations and disclosures.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Note C. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are presented in unproved properties in the consolidated balance sheets. If the exploratory well is determined to be impaired, the well costs are charged to expense.

The following table reflects the Company s capitalized exploratory well activity during the three and six months ended June 30, 2009:

(in thousands)	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Beginning capitalized exploratory well costs	$ 2,536	$ 25,553
Additions to exploratory well costs pending the determination of proved reserves	91,305	93,842
Reclassifications due to determination of proved reserves	(86,537)	(111,640)
Exploratory well costs charged to expense		(451)
Ending capitalized exploratory well costs	$ 7,304	$ 7,304

The following table provides an aging, at June 30, 2009 and December 31, 2008, of capitalized exploratory well costs based on the date drilling was completed:

(in thousands)	June 30, 2009	December 31, 2008
Wells in drilling progress	$ 533	$ 7,765
Capitalized exploratory well costs that have been capitalized for a period of one year or less	6,771	17,788
Capitalized exploratory well costs that have been capitalized for a period greater than one year		
Total capitalized exploratory well costs	$ 7,304	$ 25,553

At June 30, 2009, the Company had seven gross exploratory wells waiting on completion and two exploratory wells drilling, all of which were in the New Mexico Permian area.

Note D. ***Acquisitions***

Henry Entities acquisition. On July 31, 2008, the Company closed the acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (the Henry Entities) and additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, the Company acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. The assets acquired in the Henry Entities acquisition, including the additional non-operated interests, are referred to as the Henry Properties. The Company paid $583.5 million in cash for the Henry Properties acquisition.

The cash paid for the Henry Properties acquisition was funded with (i) borrowings under the Company s credit facility and (ii) proceeds from a private placement of approximately 8.3 million shares of the Company s common stock.

The Henry Properties acquisition is being accounted for using the purchase method of accounting for business combinations. Under the purchase method of accounting, the Company recorded the Henry Properties assets and liabilities at fair value. The

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

purchase price of the acquired Henry Properties net assets is based on the total value of the cash consideration. The initial purchase price allocation is preliminary and subject to adjustment primarily due to resolution of certain tax matters. Any future adjustments to the allocation of the total purchase price are not anticipated to be material to the Company s consolidated financial statements.

The following tables represent the preliminary allocation of the total purchase price of the Henry Properties to the acquired assets and liabilities of the Henry Properties and the consideration paid for the Henry Properties. The allocation represents the fair values assigned to each of the assets acquired and liabilities assumed:

(in thousands)	
Fair value of Henry Properties net assets:	
Current assets, net of cash acquired of $19,049 [(a)]	$ 86,005
Proved oil and natural gas properties	593,984
Unproved oil and natural gas properties	233,492
Other long-term assets	7,392
Intangible assets operating rights	38,740
Total assets acquired	959,613
Current liabilities	(113,729)
Asset retirement obligations and other long-term liabilities	(7,529)
Noncurrent derivative liabilities	(39,037)
Deferred tax liability	(215,815)
Total liabilities assumed	(376,110)
Net purchase price	$ 583,503
Consideration paid for Henry Properties net assets:	
Cash consideration paid, net of cash acquired of $19,049	$ 577,853
Acquisition costs [(b)]	5,650
Total purchase price	$ 583,503

(a) Includes a deferred tax asset of approximately $9.0 million.

(b) Acquisition costs include legal and

accounting fees, advisory fees and other acquisition-related costs.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The following unaudited pro forma combined condensed financial data for the three and six months ended June 30, 2008 was derived from the historical financial statements of the Company and Henry Properties giving effect to the acquisition as if it had occurred on January 1, 2008. The unaudited pro forma combined condensed financial data has been included for comparative purposes only and is not necessarily indicative of the results that might have occurred had the Henry Properties acquisition taken place as of the date indicated and is not intended to be a projection of future results.

(in thousands, except per share data)	**Three Months Ended June 30, 2008**	**Six Months Ended June 30, 2008**
Operating revenues	$ 185,095	$339,519
Net income	$ 5,941	$ 20,483
Earnings per common share:		
Basic	$ 0.07	$ 0.24
Diluted	$ 0.07	$ 0.24

Note E. ***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.

The following table summarizes the Company s asset retirement obligations (ARO) recorded during the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Asset retirement obligations, beginning of period	$ 18,254	$ 8,795	$ 16,809	$ 9,418
Liabilities incurred from new wells	102	275	270	309
Accretion expense	301	148	579	301
Disposition of wells sold			(142)	
Liabilities settled upon plugging and abandoning wells	(343)		(353)	
Revision of estimates	(3,928)	1,138	(2,777)	328
Asset retirement obligations, end of period	$ 14,386	$ 10,356	$ 14,386	$ 10,356

Note F. ***Stockholders equity***

Common stock private placement. On June 5, 2008, the Company entered into a common stock purchase agreement with certain unaffiliated third-party investors to sell certain shares of the Company s common stock in a private placement (the Private Placement) contemporaneous with the closing of the Henry Properties acquisition. On July 31, 2008, the Company issued 8,302,894 shares of its common stock at $30.11 per share. The Private Placement resulted in net proceeds of approximately $242.4 million to the Company, after payment of approximately $7.6 million for the fee paid to the placement agent.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Treasury stock. On June 12, 2008, the restrictions on certain restricted stock awards issued to five of the Company s executive officers lapsed. Immediately upon the lapse of restrictions, these executive officers became liable for certain federal income taxes on the value of such shares. In accordance with the Company s 2006 Stock Incentive Plan and the applicable restricted stock award agreements, four of such officers elected to deliver shares of the Company s common stock to the Company to satisfy such tax liability, and the Company acquired 3,142 shares to be held as treasury stock in the approximate amount of $125,000.

During the second quarter of 2009, the restrictions on certain restricted stock awards issued to five of the Company s executive officers lapsed. Immediately upon the lapse of restrictions, these executive officers became liable for certain federal income taxes on the value of such shares. In accordance with the Company s 2006 Stock Incentive Plan and the applicable restricted stock award agreements, all of such officers elected to deliver shares of the Company s common stock to the Company to satisfy such tax liability, and the Company acquired 6,199 shares to be held as treasury stock in the approximate amount of $192,000.

Note G. *Incentive plans*

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of all employees and maintains certain other acquired plans. The Company matches 100 percent of employee contributions, not to exceed 6 percent of the employee s annual salary. The Company contributions to the plans for the three months ended June 30, 2009 and 2008 were approximately $0.2 million and $0.1 million, respectively, and $0.5 million and $0.3 million for the six months ended June 30, 2009 and 2008, respectively.

Stock incentive plan. The Company s 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. The following table shows the number of awards available under the Company s Plan at June 30, 2009:

	Number of Common Shares
Approved and authorized awards	5,850,000
Stock option grants, net of forfeitures	(3,461,485)
Restricted stock grants, net of forfeitures	(767,787)
Awards available for future grant	1,620,728

Restricted stock awards. All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior to the lapse date, restricted shares awarded to such employee are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company s restricted stock awards activity for the six months ended June 30, 2009 is presented below:

	Number of Restricted Shares	Grant Date Fair Value Per Share
Outstanding at December 31, 2008	407,351	
Shares granted	257,398	$25.14
Shares cancelled / forfeited	(2,420)	

Lapse of restrictions	(169,519)
Outstanding at June 30, 2009	492,810

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

A summary of the impact on the consolidated statements of operations for the Company s restricted stock awards during the three and six months ended June 30, 2009 and 2008 is presented below:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Stock-based compensation expense related to restricted stock	$ 1,303	$ 468	$ 2,200	$ 862
Income tax benefit related to restricted stock	$ 586	$ 187	$ 927	$ 341
Deductions in current taxable income related to restricted stock	$ 3,989	$ 771	$ 4,367	$ 1,200

Stock option awards. A summary of the Company s stock option award activity under the Plan for the six months ended June 30, 2009 is presented below:

	Number of Options	Weighted Average Exercise Price
Outstanding at December 31, 2008	2,731,324	$ 12.46
Options granted	117,801	$ 20.40
Options exercised	(445,789)	$ 8.82
Outstanding at June 30, 2009	2,403,336	$ 13.53
Vested at end of period	1,637,752	$ 10.38
Vested and exercisable at end of period	812,760	$ 12.62

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The following table summarizes information about the Company s vested and exercisable stock options outstanding at June 30, 2009:

		Number of Stock Options	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Intrinsic Value (in thousands)
Vested options:					
June 30, 2009:					
Exercise price	$ 8.00	1,183,214	2.64 years	$ 8.00	$ 24,481
Exercise price	$ 12.00	122,516	4.85 years	$ 12.00	2,045
Exercise price	$ 15.35	210,000	6.98 years	$ 15.35	2,800
Exercise price	$ 21.85	103,500	8.67 years	$ 21.85	708
Exercise price	$ 31.33	18,522	8.90 years	$ 31.33	
		1,637,752		$ 10.38	$ 30,034
Vested and exercisable options:					
June 30, 2009:					
Exercise price	$ 8.00	394,183	3.93 years	$ 8.00	$ 8,156
Exercise price	$ 12.00	86,555	6.04 years	$ 12.00	1,445
Exercise price	$ 15.35	210,000	6.98 years	$ 15.35	2,800
Exercise price	$ 21.85	103,500	8.67 years	$ 21.85	708
Exercise price	$ 31.33	18,522	8.90 years	$ 31.33	
		812,760		$ 12.62	$ 13,109

16

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The following table summarizes information about stock-based compensation for stock options for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Grant date fair value for awards during the period:				
Time vesting options	$	$	$	$ 183
Stock option grants under the Plan		794	1,454	5,090
Total	$	$ 794	$ 1,454	$ 5,273
Stock-based compensation expense from stock options:				
Time vesting options	$ 70	$ 35	$ 141	$ 65
Performance vesting options- Officers		133	71	284
Stock option grants under the Plan	815	1,094	1,701	1,818
Total	$ 885	$ 1,262	$ 1,913	$ 2,167
Income taxes and other information:				
Income tax benefit related to stock options	$ 415	$ 504	$ 806	$ 858
Deductions in current taxable income related to stock options exercised	$ 4,117	$ 3,132	$ 7,157	$ 5,338

In calculating compensation expense for options granted during the six months ended June 30, 2009, the Company estimated the fair value of each grant using the Black-Scholes option-pricing model. Assumptions utilized in the model are shown below:

Risk-free interest rate	2.46%
Expected term (years)	6.25
Expected volatility	63.40%
Expected dividend yield	

As permitted by Staff Accounting Bulletin No. 110, *Share-Based Payment*, the Company used the simplified method to calculate the expected term for stock options granted during the three and six months ended June 30, 2009, 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. Expected volatilities are based on a combination of historical and implied volatilities of comparable companies.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Future stock-based compensation expense. Future stock-based compensation expense at June 30, 2009 is summarized in the table below:

(in thousands)	Restricted Stock	Stock Options	Total
Remaining 2009	$ 2,333	$ 1,423	$ 3,756
2010	3,431	1,694	5,125
2011	2,159	706	2,865
2012	643	166	809
2013	24	14	38
Total	$ 8,590	$ 4,003	$ 12,593

Note H. ***Disclosures about fair value of financial instruments***

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, *Effective Date of FASB Statement No. 157,* which delayed the effective date of SFAS No. 157 by one year for nonfinancial assets and liabilities. As of January 1, 2009, the Company adopted the provisions of SFAS 157 related to the Company s nonfinancial assets and liabilities, including nonfinancial assets and liabilities measured at fair value in a business combination; impaired long-lived assets; and initial recognition of asset retirement obligations. 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. 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. The Company considers active markets to be 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 the Company values 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, basis swaps, investments and interest rate swaps. The Company s valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company utilizes its counterparties valuations to assess the reasonableness of its 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, as well as investments. The Company s valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although the Company utilizes its counterparties valuations to assess the reasonableness of our prices and valuation techniques, the Company does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The following represents information about the estimated fair values of the Company s financial instruments:

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Line of credit. The carrying amount of borrowings outstanding under the Company s credit facility approximates fair value, because the instrument bears interest at variable market rates.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Derivative instruments. The fair value of the Company s derivative instruments are estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. 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 (i) summarizes the valuation of each of the Company s financial instruments by SFAS No. 157 pricing levels and (ii) summarizes the gross fair value by the appropriate balance sheet classification, in accordance with SFAS No. 161, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company s consolidated balance sheets at June 30, 2009 and December 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 June 30, 2009
Assets [1]				
Current: [a]				
Commodity derivative price swap contracts	$	$ 26,408	$	$ 26,408
Commodity derivative basis swap contracts				
Interest rate derivative swap contracts				
Commodity derivative price collar contracts			18,856	18,856
		26,408	18,856	45,264
Noncurrent: [b]				
Commodity derivative price swap contracts		43,604		43,604
Commodity derivative basis swap contracts				
Interest rate derivative swap contracts		3,541		3,541
Commodity derivative price collar contracts				
		47,145		47,145
Liabilities [1]				
Current: [a]				
Commodity derivative price swap contracts		(27,650)		(27,650)
Commodity derivative basis swap contracts		(2,456)		(2,456)
Interest rate derivative swap contracts		(3,624)		(3,624)
Commodity derivative price collar contracts			(993)	(993)

		(33,730)	(993)	(34,723)
Noncurrent: [b]				
Commodity derivative price swap contracts		(29,782)		(29,782)
Commodity derivative basis swap contracts		(1,476)		(1,476)
Interest rate derivative swap contracts				
Commodity derivative price collar contracts			(2,105)	(2,105)
		(31,258)	(2,105)	(33,363)
Total financial assets (liabilities)	$	$ 8,565	$ 15,758	$ 24,323

(a) Total current financial assets (liabilities), gross basis	$ 10,541
(b) Total noncurrent financial assets (liabilities), gross basis	13,782
Total financial assets (liabilities)	$ 24,323

20

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

(in thousands)	Fair value measurements using Quoted prices in active markets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	Total carrying value at December 31, 2008
Assets [1]				
Current: [a]				
Commodity derivative price swap contracts	$	$ 64,162	$	$ 64,162
Commodity derivative basis swap contracts				
Interest rate derivative swap contracts				
Commodity derivative price collar contracts			49,562	49,562
		64,162	49,562	113,724
Noncurrent: [b]				
Commodity derivative price swap contracts		60,995		60,995
Commodity derivative basis swap contracts				
Interest rate derivative swap contracts		678		678
Commodity derivative price collar contracts				
		61,673		61,673
Liabilities [1]				
Current: [a]				
Commodity derivative price swap contracts				
Commodity derivative basis swap contracts		(680)		(680)
Interest rate derivative swap contracts		(1,761)		(1,761)
Commodity derivative price collar contracts				
		(2,441)		(2,441)
Noncurrent: [b]				
Commodity derivative price swap contracts		(516)		(516)
Commodity derivative basis swap contracts				
Interest rate derivative swap contracts				
Commodity derivative price collar contracts				
		(516)		(516)
Total financial assets (liabilities)	$	$ 122,878	$ 49,562	$ 172,440

(a) Total current financial assets (liabilities), gross basis	$	111,283
(b) Total noncurrent financial assets (liabilities), gross basis		61,157
Total financial assets (liabilities)	$	172,440

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

(1) The fair value of derivative instruments reported in the Company s consolidated balance sheets are subject to netting arrangements and qualify for net presentation. The following table reports the net basis derivative fair values as reported in the consolidated balance sheets at June 30, 2009 and December 31, 2008:

	June 30, 2009	December 31, 2008
Consolidated Balance Sheet Classification:		
Current derivative contracts:		
Assets	$ 26,272	$ 113,149
Liabilities	(15,731)	(1,866)
Net current	$ 10,541	$ 111,283
Noncurrent derivative contracts:		
Assets	$ 31,438	$ 61,157
Liabilities	(17,656)	
Net noncurrent	$ 13,782	$ 61,157

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)	
Balance at December 31, 2008	$ 49,562
Realized and unrealized losses	(9,686)
Purchases, issuances, and settlements	(24,118)
Balance at June 30, 2009	$ 15,758
Total losses for the period included in earnings attributable to the change in unrealized losses relating to assets still held at the reporting date	$ (33,804)

For additional information on the Company s derivative instruments see Note I.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company s consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets In accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the Company reviews its long-lived assets to be held and used, including proved oil and gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and gas properties by amortization base or by individual well for those wells not constituting part of an amortization base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and unproved oil and gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The Company periodically reviews its proved oil and gas properties that are sensitive to oil and natural gas prices for impairment. Due to downward adjustments to the economically recoverable resource potential associated with declines in commodity prices and well performance, the Company recognized impairment expense of $4.5 million and $8.6 million for the three and six months ended June 30, 2009, respectively, related to its proved oil and gas properties. For the three months ended June 30, 2009, the impaired assets, which had a total carrying amount of $7.3 million, were reduced to their estimated fair value of $2.8 million. For the six months ended June 30, 2009, the impaired assets, which had a total carrying amount of $14.2 million, were reduced to their estimated fair value of $5.6 million.

Asset Retirement Obligations The Company estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO; amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. See Note E for a summary of changes in AROs.

Measurement information for assets that are measured at fair value on a nonrecurring basis was as follows:

	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 Impairment Loss
Three months ended June 30, 2009:				
Impairment of long-lived assets	$	$	$ 2,733	$(4,499)
Asset retirement obligations incurred in current period			102	
Three months ended June 30, 2008:				
Impairment of long-lived assets	$	$	$ 7	$ (53)
Asset retirement obligations incurred in current period			275	
Six months ended June 30, 2009:				
Impairment of long-lived assets	$	$	$ 5,620	$(8,555)
Asset retirement obligations incurred in current period			270	
Six months ended June 30, 2008:				
Impairment of long-lived assets	$	$	$ 7	$ (69)
Asset retirement obligations incurred in current period			309	

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Note I. ***Derivative financial instruments***

The Company uses derivative financial contracts to manage exposures to commodity price and interest rate fluctuations. Commodity hedges are used to (i) reduce the effect of the volatility of price changes on the natural gas and oil the Company produces and sells, (ii) support the Company s capital budget and expenditure plans and (iii) support the economics associated with acquisitions. Interest rate hedges are used to mitigate the cash flow risk associated with rising interest rates. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company also may enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company s consolidated financial statements.

Currently, the Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its statements of operations. All of the Company s remaining hedges that historically qualified for hedge accounting or were dedesignated from hedge accounting were settled in 2008.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

New commodity derivatives contracts in 2009. During the six months ended June 30, 2009, the Company entered into additional commodity derivative contracts to hedge a portion of its estimated future production. The following table summarizes information about these additional commodity derivative contracts:

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price collar	600,000	$ 45.00 $49.00(a)(d)	3/1/09 5/31/09
Price swap	270,000	$ 69.50(a)	7/1/09 9/30/09
Price swap	540,000	$ 51.62(a) (d)	7/1/09 12/31/09
Price swap	150,000	$ 69.50(a)	10/1/09 12/31/09
Price swap	2,508,000	$ 62.15(a) (d)	1/1/10 12/31/10
Price swap	1,800,000	$ 72.17(a) (d)	1/1/11 12/31/11
Natural gas (volumes in MMBtus):			
Price collar	1,500,000	$ 5.00 $5.81(b)	10/1/09 12/31/09
Price collar	1,500,000	$ 5.00 $5.81(b)	1/1/10 3/31/10
Price collar	3,000,000	$ 5.25 $5.75(b)	4/1/10 9/30/10
Price collar	1,500,000	$ 6.00 $6.80(b)	10/1/10 12/31/10
Price collar	1,500,000	$ 6.00 $6.80(b)	1/1/11 3/31/11
Price swap	3,000,000	$ 4.31(b)	4/1/09 9/30/09
Price swap	600,000	$ 4.66(b)	7/1/09 9/30/09
Price swap	450,000	$ 4.66(b)	10/1/09 12/31/09
Price swap	2,400,000	$ 6.31(b)	1/1/10 12/31/10
Price swap	300,000	$ 7.29(b)	1/1/11 3/31/11
Price swap	5,400,000	$ 6.96(b) (d)	4/1/11 12/31/11

Basis swap	600,000	$	0.79(c)	7/1/09 9/30/09
Basis swap	450,000	$	0.89(c)	10/1/09 12/31/09
Basis swap	8,400,000	$	0.85(c) (d)	1/1/10 12/31/10
Basis swap	1,800,000	$	0.87(c) (d)	1/1/11 3/31/11
Basis swap	5,400,000	$	0.76(c)	4/1/11 12/31/11

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

(b) The index prices for the natural gas price swaps and collars are based on the NYMEX-Henry Hub last trading day futures price.

(c) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

(d) Prices represent weighted average prices.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

In July 2009, the Company entered into the following oil price swaps to hedge an additional portion of its estimated oil production:

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price swap	273,000	$67.50(a)	8/1/09 - 12/31/09
Price swap	799,000	$67.50(a)	1/1/10 - 12/31/10
Price swap	801,000	$70.53(a) (b)	1/1/11 - 12/31/11

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

(b) Prices represent weighted average prices.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Commodity derivative contracts at June 30, 2009. The following table sets forth the Company s outstanding commodity derivative contracts at June 30, 2009:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: [(a)]					
2009:					
Volume (Bbl)			995,473	875,473	1,870,946
Price per Bbl [(e)]			$ 72.71	$ 73.15	$ 72.92
2010:					
Volume (Bbl)	787,436	787,436	787,436	787,436	3,149,744
Price per Bbl [(e)]	$ 68.49	$ 68.49	$ 68.49	$ 68.49	$ 68.49
2011:					
Volume (Bbl)	589,436	589,436	589,436	589,436	2,357,744
Price per Bbl [(e)]	$ 79.91	$ 79.91	$ 79.91	$ 79.91	$ 79.91
2012:					
Volume (Bbl)	126,000	126,000	126,000	126,000	504,000
Price per Bbl	$ 127.80	$ 127.80	$ 127.80	$ 127.80	$ 127.80
Oil Collars: [(a)]					
2009:					
Volume (Bbl)			192,000	192,000	384,000
Price per Bbl			$ 120.00 - $134.60	$ 120.00 - $134.60	$ 120.00 - $134.60
Natural Gas Swaps: [(b)]					
2009:					
Volume (MMBtu)			460,000	460,000	920,000
Price per MMBtu			$ 8.44	$ 8.44	$ 8.44
Natural Gas Swaps: [(c)]					
2009:					
Volume (MMBtu)			2,100,000	450,000	2,550,000
Price per MMBtu			$ 4.41	$ 4.66	$ 4.45
2010:					
Volume (MMBtu)	600,000	600,000	600,000	600,000	2,400,000
	$ 6.31	$ 6.31	$ 6.31	$ 6.31	$ 6.31

Price per MMBtu					
2011:					
Volume (MMBtu)	300,000	1,800,000	1,800,000	1,800,000	5,700,000
Price per MMBtu	$ 7.29	$ 6.96	$ 6.96	$ 6.96	$ 6.98
Natural Gas Collars: [(c)]					
2009:					
Volume (MMBtu)				1,500,000	1,500,000
Price per MMBtu				$ 5.00 - $5.81	$ 5.00 - $5.81
2010:					
Volume (MMBtu)	1,500,000	1,500,000	1,500,000	1,500,000	6,000,000
Price per MMBtu	$ 5.00 - $5.81	$ 5.25 - $5.75	$ 5.25 - $5.75	$ 6.00 - $6.80	$ 5.38 - $6.03
2011:					
Volume (MMBtu)	1,500,000				1,500,000
Price per MMBtu	$ 6.00 - $6.80				$ 6.00 - $6.80

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Natural Gas Basis Swaps: **(d)**					
2009:					
Volume (MMBtu)			2,118,000	1,968,000	4,086,000
Price per MMBtu (e)			$ 0.99	$ 1.03	$ 1.01
2010:					
Volume (MMBtu)	2,100,000	2,100,000	2,100,000	2,100,000	8,400,000
Price per MMBtu (e)	$ 0.85	$ 0.85	$ 0.85	$ 0.85	$ 0.85
2011:					
Volume (MMBtu)	1,800,000	1,800,000	1,800,000	1,800,000	7,200,000
Price per MMBtu (e)	$ 0.87	$ 0.76	$ 0.76	$ 0.76	$ 0.79

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

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

(c) The index prices for the natural gas price swaps and collars are based on the NYMEX-Henry Hub last trading day futures price.

(d) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

(e) Prices represent weighted average prices.

Interest rate derivative contracts at June 30, 2009. The Company has an interest rate swap which fixes the LIBOR interest rate on $300 million of the Company s bank debt at 1.90 percent for three years, commencing in May of 2009. For this portion of the Company s bank debt, the all-in interest rate will be calculated by adding the fixed rate of 1.90 percent to a margin that ranges from 2.00 percent to 3.00 percent depending on the amount of bank debt outstanding.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The Company s reported oil and natural gas revenue and average oil and natural gas prices includes the effects of oil quality and Btu content, gathering and transportation costs, natural gas processing and shrinkage, and the net effect of the commodity hedges that qualified for cash flow hedge accounting. The following table summarizes the gains and losses reported in earnings related to the commodity and interest rate derivative instruments and the net change in accumulated other comprehensive income (AOCI) for the three and six months ended June 30, 2009 and 2008*:*

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Decrease in oil and natural gas revenue from derivative activity:				
Cash payments on cash flow hedges in oil sales	$	$ (13,367)	$	$ (20,573)
Dedesignated cash flow hedges reclassified from AOCI in natural gas sales		74		(222)
Total decrease in oil and natural gas revenue from derivative activity	$	$ (13,293)	$	$ (20,795)
Loss on derivatives not designated as hedges:				
Mark-to-market gain (loss):				
Commodity derivatives	$ (109,374)	$ (90,055)	$ (149,117)	$ (103,247)
Interest rate derivatives	3,427		1,000	
Cash (payments) receipts on derivatives not designated as hedges:				
Commodity derivatives	25,120	(12,401)	62,244	(16,387)
Interest rate derivatives	(779)		(779)	
Total loss on derivatives not designated as hedges	$ (81,606)	$ (102,456)	$ (86,652)	$ (119,634)
Gain from ineffective portion of cash flow hedges	$	$ 356	$	$ 920
Accumulated other comprehensive income (loss):				
Cash flow hedges:				
Mark-to-market loss of cash flow hedges	$	$ (25,903)	$	$ (32,510)
Reclassification adjustment of losses to earnings		13,367		20,573

Net change, before income taxes			(12,536)				(11,937)
Income tax effect			4,899				4,665
Net change, net of income taxes	$	$	(7,637)	$		$	(7,272)
Dedesignated cash flow hedges:							
Reclassification adjustment of (gains) losses to earnings	$	$	(74)	$		$	222
Income tax effect			29				(87)
Net change, net of income taxes	$	$	(45)	$		$	135

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Note J. ***Debt***

The Company s debt consisted of the following:

(in thousands)	June 30, 2009	December 31, 2008
Credit facility	$ 660,000	$ 630,000
Less: current portion		
Total long-term debt	$ 660,000	$ 630,000

Credit facility. The Company s credit facility, as amended, has a maturity date of July 31, 2013 (the Credit Facility). At June 30, 2009, the Company had letters of credit outstanding under the Credit Facility of approximately $25,000 and its availability to borrow additional funds was approximately $300 million. In April 2009, the lenders reaffirmed the Company s $960 million borrowing base under the Credit Facility until the next scheduled borrowing base redetermination in October 2009. Between scheduled borrowing base redeterminations, the Company and, if requested by 66 2/3 percent of the lenders, the lenders, may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Company s option, based on (i) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (3.25 percent at June 30, 2009) or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). At June 30, 2009, the interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 200 to 300 basis points and 112.5 to 212.5 basis points, respectively, per annum depending on the debt balance outstanding. At June 30, 2009, the Company pays commitment fees on the unused portion of the available borrowing base of 50 basis points per annum.

The Credit Facility also includes a same-day advance facility under which the Company may borrow funds from the administrative agent. Same day advances 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.

The Company s obligations under the Credit Facility are secured by a first lien on substantially all of the Company s oil and natural gas properties. In addition, all of the Company s subsidiaries are guarantors and all general partner, limited partner and membership interests in the Company s subsidiaries owned by the Company have been pledged to secure borrowings under the Credit Facility. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios, including (i) 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 to be no greater than 4.0 to 1.0, and (ii) a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including the unfunded amounts under the Credit Facility, 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 mergers, combinations and dispositions of assets; and (d) restrictions on the payment of cash dividends. At June 30, 2009, the Company was in compliance with its debt covenants under the Credit Facility.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Principal maturities of debt. Principal maturities of debt outstanding at June 30, 2009 are as follows:

(in thousands)	
Remaining 2009	$
2010	
2011	
2012	
2013	660,000
Total	$ 660,000

Interest expense. The following amounts have been incurred and charged to interest expense for the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Cash payments for interest	$ 3,457	$ 3,982	$ 6,929	$ 10,758
Amortization of original issue discount		25		50
Amortization of deferred loan origination costs	857	314	1,713	626
Write-off of deferred loan origination costs and original issue discount				
Net changes in accruals	1,889	(71)	1,946	(1,094)
Interest costs incurred	6,203	4,250	10,588	10,340
Less: capitalized interest	(3)	(365)	(18)	(840)
Total interest expense	$ 6,200	$ 3,885	$ 10,570	$ 9,500

Note K. *Commitments and contingencies*

Severance agreements. The Company has entered into severance and change of control agreements with all of its officers. The current annual salaries for the Company s officers covered under such agreements total approximately $1.9 million.

Indemnifications. The Company has agreed to indemnify its directors and officers, with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company s consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a quarter-by-quarter basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Acquisition commitments. In connection with the acquisition of the Henry Entities, the Company agreed to pay certain employees, who were formerly employed by the Henry Entities, bonuses of approximately $11.0 million in the aggregate at each of the first and second anniversaries of the closing of the acquisition, respectively. Except as described below, these employees must remain employed with the Company to receive the bonus. A former Henry Entities employee who is otherwise entitled to a full bonus will receive the full bonus (i) if the Company terminates the employee without cause, (ii) upon the death or disability of such employee or (iii) upon a change in control of the Company. If any such employee resigns or is terminated for cause, the employee will not receive the bonus and, subject to certain conditions, the Company will be required to reimburse the sellers in the acquisition of the Henry Entities 65 percent of the bonus amount not paid to the employee. The Company will reflect the bonus amounts to be paid

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

to these employees as a period cost, which will be included in the Company s results of operations over the period earned. Amounts that ultimately are determined to be paid to the sellers will be treated as a contingent purchase price and reflected as an adjustment to the purchase price. During the three and six months ended June 30, 2009, the Company recognized $2.8 million and $5.3 million, respectively, of this obligation in its results of operations.

Daywork commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds to drill wells in the future, including agreements to secure drilling rig services, which require the Company to make future minimum payments to the rig operators. The Company records drilling commitments in the periods in which well capital is incurred or rig services are provided. The following table summarizes the Company s future drilling commitments at June 30, 2009:

		Payments Due By Period			
(in thousands)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Daywork drilling contracts	$ 299	$ 299	$	$	$
Daywork drilling contracts with related parties [(a)]	1,000	1,000			
Daywork drilling contracts assumed in the Henry Properties acquisition [(b)]	1,629	1,629			
Total contractual drilling commitments	$ 2,928	$ 2,928	$	$	$

(a) Consists of daywork drilling contracts with Silver Oak Drilling, LLC, an affiliate of Chase Oil Corporation.

(b) A major oil and gas company which owns an interest in the wells being drilled and the Company are parties to these contracts. Only the Company s 25% share of the contract obligation has been reflected above.

Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the three months ended June 30, 2009 and 2008 were approximately $582,000 and $116,000, respectively, and $1,253,000 and $280,000 for the six months ended June 30, 2009 and 2008, respectively. Future minimum lease commitments under non-cancellable operating leases at June 30, 2009 are as follows:

(in thousands)	
Remaining 2009	$ 523
2010	1,077
2011	1,083
2012	1,077
2013	1,084
Thereafter	3,261
Total	$ 8,105

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 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,* an interpretation of FASB Statement No. 109, *Accounting for Income Taxes,* on January 1, 2007. At the time of adoption and at June 30, 2009, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 through 2008 remain subject to examination by major tax jurisdictions.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The FASB issued FIN No. 48-1, *Definition of Settlement in FASB Interpretation No. 48* (FIN No. 48-1), to clarify when a tax position is effectively settled. FIN No. 48-1 provides guidance 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 consolidated financial statements.

Income tax provision. The Company s income tax provision and amounts separately allocated were attributable to the following items for the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Income (loss) from operations	$ (25,691)	$ (9,169)	$ (33,797)	$ 5,199
Changes in stockholders equity:				
Net deferred hedge losses		(10,123)		(12,705)
Net settlement losses included in earnings		5,195		8,127
Tax benefits related to stock-based compensation	(2,188)	(1,553)	(2,992)	(2,146)
	$ (27,879)	$ (15,650)	$ (36,789)	$ (1,525)

The Company s income tax provision (benefit) attributable to income (loss) from operations consisted of the following for the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Current:				
U.S. federal	$ 2,856	$ 523	$ 5,294	$ 585
U.S. state and local	381	98	708	110
	3,237	621	6,002	695
Deferred:				
U.S. federal	(25,518)	(8,201)	(35,103)	3,790
U.S. state and local	(3,410)	(1,589)	(4,696)	714
	(28,928)	(9,790)	(39,799)	4,504
	$ (25,691)	$ (9,169)	$ (33,797)	$ 5,199

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The reconciliation between the tax expense computed by multiplying pretax income (loss) by the U.S. federal statutory rate and the reported amounts of income tax expense (benefit) is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Income (loss) at U.S. federal statutory rate	$ (20,618)	$ (8,256)	$ (28,084)	$ 4,600
State income taxes (net of federal tax effect)	(1,969)	(968)	(2,592)	537
Nondeductible expense & other	(3,104)	55	(3,121)	62
Income tax expense (benefit)	$ (25,691)	$ (9,169)	$ (33,797)	$ 5,199

Note M. *Related party transactions*

Consulting Agreement. On June 30, 2009, Steven L. Beal, the Company s President and Chief Operating Officer, retired from such positions. Mr. Beal was recently re-elected to the Company s Board of Directors and is continuing to serve as a member of the Company s Board of Directors. On June 9, 2009, the Company entered into a consulting agreement (the Consulting Agreement) with Mr. Beal, under which Mr. Beal began serving as a consultant to the Company on July 1, 2009. Either the Company or Mr. Beal may terminate the consulting relationship at any time by giving ninety days written notice to the other party; however, the Company may terminate the relationship immediately for cause. During the term of the consulting relationship, Mr. Beal will receive a consulting fee of $20,000 per month and a monthly reimbursement for his medical and dental coverage costs. If Mr. Beal dies during the term of the Consulting Agreement, his estate will receive a $60,000 lump sum payment.

Chase Group transactions. The Company incurred charges from Mack Energy Corporation (MEC), an affiliate of Chase Oil Corporation (Chase Oil), of approximately $0.4 million and $0.3 million for the three months ended June 30, 2009 and 2008, respectively, and $0.7 million and $1.5 million for the six months ended June 30, 2009 and 2008, respectively, for services rendered in the ordinary course of business.

The Company had $112,000 in outstanding receivables due from MEC at June 30, 2009 and no outstanding receivables due from MEC at December 31, 2008. The Company had $49,000 in outstanding payables to MEC at June 30, 2009 and no outstanding payables to MEC at December 31, 2008.

Saltwater disposal services agreement. Among the assets the Company acquired from Chase Oil is an undivided interest in a saltwater gathering and disposal system, which is owned and maintained under a written agreement among the Company and Chase Oil and certain of its affiliates, and under which the Company as operator gathers and disposes of produced water. The system is owned jointly by the Company and Chase Oil and its affiliates in undivided ownership percentages, which are annually redetermined as of January 1 on the basis of each party s percentage contribution of the total volume of produced water disposed of through the system during the prior calendar year. As of January 1, 2009, the Company owned 95.4% of the system and Chase Oil and its affiliates owned 4.6%.

Other related party transactions. The Company also has engaged in transactions with certain other affiliates of Chase Oil, Caza Energy LLC (Caza) and certain other parties thereto (collectively the Chase Group), including a drilling contractor, 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 $6.2 million and $5.7 million for the three months ended June 30, 2009 and 2008, respectively, and $12.6 million and $13.1 million for the six months ended June 30, 2009 and 2008, respectively.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The Company had outstanding amounts payable to these related party vendors identified above of approximately $1.0 million and $21,000 at June 30, 2009 and December 31, 2008, respectively, which are reflected in accounts payable related parties in the accompanying consolidated balance sheets.

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 $258,000 and $816,000 for the three months ended June 30, 2009 and 2008, respectively, and $499,000 and $1,600,000 for the six months ended June 30, 2009 and 2008, respectively. The Company owed these owners royalty payments of approximately $132,000 and $146,000 at June 30, 2009 and December 31, 2008, 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 owner of a 3.5% partnership interest. The Company paid this partnership approximately $30,000 and $81,000 for the three months ended June 30, 2009 and 2008, respectively, and $56,000 and $164,000 for the six months ended June 30, 2009 and 2008, respectively. The Company owed this partnership royalty payments of approximately $13,000 at June 30, 2009 and December 31, 2008.

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 and six months ended June 30, 2009 and 2008, no payments were made related to this overriding royalty interest. Effective March 31, 2008, the executive officer involved in this matter resigned from the Company.

Working interests owned by employees. As part of the Henry Properties acquisition, the Company purchased oil and natural gas properties in which certain employees owned interests. The Company distributed revenues to these employees totaling approximately $32,000 and $62,000 for the three and six months ended June 30, 2009, respectively, and received joint interest payments from these employees of approximately $245,000 and $884,000 for the three and six months ended June 30, 2009, respectively. At June 30, 2009 and December 31, 2008, the Company was owed by these employees approximately $63,000 and $300,000, respectively, which is reflected in accounts receivable related parties.

Note N. ***Net income (loss) per share***

Basic net income (loss) per share is computed by dividing net income (loss) applicable to common shareholders by the weighted average number of common shares treated as outstanding for the period. All capital options were exercised prior to March 31, 2008.

The computation of diluted income (loss) per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income (loss) 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 stock options and restricted stock (as issued under the Plan and described in Note G). Potentially dilutive effects are calculated using the treasury stock method.

Table of Contents

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in thousands)	**2009**	**2008**	**2009**	**2008**
Weighted average common shares outstanding:				
Basic	84,799	75,665	84,665	75,569
Dilutive capital options				12
Dilutive common stock options				1,206
Dilutive restricted stock				247
Diluted	84,799	75,665	84,665	77,034

For the three and six months ended June 30, 2009, the computation of diluted net loss per share was anti-dilutive due to the net loss reported by the Company; therefore, the amounts reported for basic and diluted net loss per share were the same. For the three and six months ended June 30, 2009, 492,810 shares of restricted stock, respectively, and 2,403,336 stock options, respectively, were not included in the computation of diluted loss per share, as inclusion of these items would be anti-dilutive.

For the three months ended June 30, 2008, the computation of diluted net loss per share was anti-dilutive due to the net loss reported by the Company; therefore, the amounts reported for basic and diluted net loss per share were the same. For the three and six months ended June 30, 2008, 379,794 and 24,914 shares of restricted stock, respectively, and 3,043,971 and 305,278 stock options, respectively, were not included in the computation of diluted loss per share, as inclusion of these items would be anti-dilutive.

Note O. ***Other current liabilities***

The following table provides the components of the Company s other current liabilities at June 30, 2009 and December 31, 2008:

(in thousands)	**June 30, 2009**	**December 31, 2008**
Other current liabilities:		
Accrued production costs	$ 18,229	$ 15,489
Payroll related matters	11,843	11,290
Accrued interest	2,299	353
Asset retirement obligations	2,706	2,611
Other	3,072	8,314
Other current liabilities	$ 38,149	$ 38,057

Note P. ***Subsequent events***

The Company has evaluated subsequent events through August 6, 2009, which was the date these financial statements were issued.

Concho Resources Inc.
Condensed Notes to Consolidated Financial Statements
June 30, 2009
Unaudited

Note Q. ***Supplementary information***
Capitalized costs

(in thousands)	June 30, 2009	December 31, 2008
Oil and natural gas properties:		
Proved	$ 2,608,138	$ 2,316,330
Unproved	277,137	377,244
Less: accumulated depletion	(413,252)	(306,990)
Net capitalized costs for oil and natural gas properties	$ 2,472,023	$ 2,386,584

Costs incurred for oil and natural gas producing activities **(a)**

(in thousands)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Property acquisition costs:[(b)]				
Proved	$ (68)	$ (104)	$ (1,008)	$ 1
Unproved	3,361	587	4,582	1,349
Exploration	61,131	21,136	84,940	50,701
Development	31,450	46,365	115,229	71,242
Total costs incurred for oil and natural gas properties	$ 95,874	$ 67,984	$ 203,743	$ 123,293

(a) The costs incurred for oil and natural gas producing activities includes the following amounts of asset retirement obligations:

(in thousands)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008

Proved property acquisition costs	$	$	$	$
Exploration costs	52	168	220	194
Development costs	(3,878)	1,245	(2,727)	443
Total	$ (3,826)	$ 1,413	$ (2,507)	$ 637

(b) During the three and six months ended June 30, 2009, the Company adjusted the purchase price allocation related to the acquisition of the Henry Properties. This adjustment reduced the proved acquisition costs by $80,000 and $1,020,000 during the three and six months ended June 30, 2009, respectively, while the unproved acquisition costs were decreased by $298,000 and increased by $293,000 during the three and six months ended June 30, 2009, respectively.

Table of Contents

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

The following discussion is intended to assist 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, 2008.

During the third quarter of 2008, we closed a significant acquisition as discussed below. As a result of the acquisition many comparisons between periods will be difficult or impossible.

Statements in this 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. See Cautionary statement regarding forward-looking statements.

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 operations are primarily focused in the Permian Basin of Southeastern New Mexico and West Texas. We have also acquired significant acreage positions in and are actively involved in drilling or participating in drilling in emerging plays located in the Permian Basin of Southeastern New Mexico and the Williston Basin in North Dakota, where we are applying horizontal drilling and advanced fracture stimulation. Oil comprised 62.9 percent of our 137.3 MMBoe of estimated net proved reserves at December 31, 2008, and 64.8 percent of our 7.1 MMBoe of production in 2008. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 93.1 percent of our proved developed producing PV-10 and 64.7 percent of our 3,553 gross wells at December 31, 2008. By controlling operations, we believe that 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.

Commodity prices

Factors that may impact future commodity prices, including the price of oil and natural gas, include:

- developments generally impacting the Middle East, including Iraq and Iran;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil supply through export quotas;
- the overall global demand for oil; and
- overall North American natural gas supply and demand fundamentals, including:
  - § the impact of the decline of the United States economy,
  - § weather conditions, and
  - § liquefied natural gas deliveries to the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note I of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding our commodity hedge positions at June 30, 2009.

Oil prices in 2008 were high and particularly volatile compared to historical prices. In addition, natural gas prices have been subject to significant fluctuations during the past several years. In general, oil and natural gas prices were substantially lower during the comparable periods of 2009 measured against 2008. The following table sets forth the average NYMEX oil and natural gas prices for the three and six months ended June 30, 2009 and 2008, as well as, the high and low NYMEX price for the same periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Average NYMEX prices:				
Oil (Bbl)	$59.83	$124.28	$51.61	$110.98
Natural gas (MMBtu)	$ 3.80	$ 11.48	$ 4.15	$ 10.10
High / Low NYMEX prices:				
Oil (Bbl):				
High	$72.68	$140.21	$72.68	$140.21
Low	$45.88	$100.98	$33.98	$ 86.99
Natural gas (MMBtu):				
High	$ 4.45	$ 13.35	$ 6.07	$ 13.35
Low	$ 3.25	$ 9.32	$ 3.25	$ 7.48

Further demonstrating the continuing volatility, the NYMEX oil price and NYMEX natural gas price reached lows of $59.52 per Bbl and $3.26 per MMBtu, respectively, during the period from July 1, 2009 to August 3, 2009. At August 3, 2009, the NYMEX oil price and NYMEX natural gas price were $71.58 per Bbl and $4.03 per MMBtu, respectively.

Henry Entities acquisition

On July 31, 2008, we closed the acquisition of Henry Petroleum LP and certain entities affiliated with Henry Petroleum LP (the Henry Entities) and additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. In August 2008 and September 2008, we acquired additional non-operated interests in oil and natural gas properties from persons affiliated with the Henry Entities. The assets acquired in the Henry Entities acquisition, including the additional non-operated interests, are referred to as the Henry Properties. We paid $583.5 million in cash for the Henry Properties acquisition, which was funded with borrowings under our credit facility, which was amended and restated on July 31, 2008, and net proceeds of approximately $242.4 million from our private placement of 8,302,894 shares of our common stock.

2009 capital budget

On November 6, 2008, our board of directors approved the following capital budget for 2009, predicated on funding it substantially within our cash flow:

(in millions)	**2009 Budget**
Drilling and recompletion opportunities in our core operating area	$ 398
Projects operated by third parties	8
Emerging plays, acquisition of leasehold acreage and other property interests, and geological and geophysical	72
Maintenance capital in our core operating areas	22

Total 2009 capital budget	$ 500

In January 2009, in light of the drop in commodity prices, we took actions to reduce our capital activities to a level that would allow us to fund our capital expenditures substantially within our cash flow, which at the time resulted in estimated annual capital expenditures of approximately $300 million. Currently, based on current capital costs and commodity prices, we estimate our capital expenditures to be approximately $400 million for 2009, which we believe we can substantially fund within our cash flow. We will continue to monitor our capital expenditures, at least on a quarterly basis, in relation to our cash flow and expect to adjust our activity and capital spending level based on changes in commodity prices and the cost of goods and services and other considerations.

During the first half of 2009, we incurred approximately $207.0 million of capital expenditures (excluding the effects of asset retirement obligations and adjustments to the acquisition of the Henry Properties). These costs were modestly in excess of our cash flows (including effects of derivative cash receipts/payments) during the first half of 2009.

Reaffirmed borrowing base

We amended our credit agreement on April 7, 2009, to (i) reaffirm our borrowing base of $960 million; (ii) add certain provisions relating to defaulting lenders which, among other things, require us, at the request of the administrative agent, to cash collateralize or prepay a defaulting lender s pro rata share of letter of credit and swingline loan exposure; (iii) amend the calculation of alternate base rate interest, which is used in connection with non-Eurodollar rate loans from the greater of (a) the JPMorgan Chase Bank prime rate or (b) the federal funds rate plus 0.50% to the greatest of the (x) JPMorgan Chase Bank prime rate, (y) the federal funds rate plus 0.50% and (z) the rate for one-month U.S. dollar deposits in the London interbank market plus 1.00% and (iv) revise the pricing schedule to increase (a) the Eurodollar rate margin from a range of 1.25% to 2.75% to a range of 2.00% to 3.00% (depending on the then-current borrowing base usage), (b) the alternate base rate margin from a range of 0.00% to 1.25% to a range of 1.125% to 2.125% (depending on the then-current borrowing base usage), and (c) the unused commitment fee rate from a range of 0.25% to 0.50% to a flat rate of 0.50%.

Derivative financial instrument exposure

At June 30, 2009, the fair value of our financial derivatives was a net asset of $24.3 million. All of our counterparties to these financial derivatives are parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Pursuant to the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential margin calls on our financial derivative instruments.

We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender under our credit facility against amounts we may be owed related to our derivative financial instruments with such party.

New commodity derivative contracts. During the six months ended June 30, 2009, we entered into additional commodity derivative contracts to economically hedge a portion of our estimated future production. The following table summarizes information about these additional commodity derivative contracts:

	Aggregate Volume	Index Price		Contract Period
Oil (volumes in Bbls):				
Price collar	600,000	$ 45.00	$49.00 [a] [d]	3/1/09 5/31/09
Price swap	270,000	$	69.50 [a]	7/1/09 9/30/09
Price swap	540,000	$	51.62 [a] [d]	7/1/09 12/31/09
Price swap	150,000	$	69.50 [a]	10/1/09 12/31/09
Price swap	2,508,000	$	62.15 [a] [d]	1/1/10 12/31/10
Price swap	1,800,000	$	72.17 [a] [d]	1/1/11 12/31/11
Natural gas (volumes in MMBtus):				
Price collar	1,500,000	$ 5.00	$5.81 [b]	10/1/09 12/31/09
Price collar	1,500,000	$ 5.00	$5.81 [b]	1/1/10 3/31/10
Price collar	3,000,000	$ 5.25	$5.75 [b]	4/1/10 9/30/10
Price collar	1,500,000	$ 6.00	$6.80 [b]	10/1/10 12/31/10
Price collar	1,500,000	$ 6.00	$6.80 [b]	1/1/11 3/31/11
Price swap	3,000,000	$	4.31 [b]	4/1/09 9/30/09
Price swap	600,000	$	4.66 [b]	7/1/09 9/30/09
Price swap	450,000	$	4.66 [b]	10/1/09 12/31/09
Price swap	2,400,000	$	6.31 [b]	1/1/10 12/31/10
Price swap	300,000	$	7.29 [b]	1/1/11 3/31/11
Price swap	5,400,000	$	6.96 [b] [d]	4/1/11 12/31/11
Basis swap	600,000	$	0.79 [c]	7/1/09 9/30/09
Basis swap	450,000	$	0.89 [c]	

				10/1/09 12/31/09
Basis swap	8,400,000	$	0.85 (c) (d)	1/1/10 12/31/10
Basis swap	1,800,000	$	0.87 (c) (d)	1/1/11 3/31/11
Basis swap	5,400,000	$	0.76 (c)	4/1/11 12/31/11

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

(b) The index prices for the natural gas price swaps and collars are based on the NYMEX-Henry Hub last trading day futures price.

(c) The basis differential between the El Paso Permian delivery point and NYMEX Henry Hub delivery point.

(d) Prices represent weighted average prices.

Table of Contents

In July 2009, the Company entered into the following oil price swaps to hedge an additional portion of its estimated oil production:

	Aggregate Volume	Index Price	Contract Period
Oil (volumes in Bbls):			
Price swap	273,000	$67.50 [a]	8/1/09 - 12/31/09
Price swap	799,000	$67.50 [a]	1/1/10 - 12/31/10
Price swap	801,000	$70.53 [a] [b]	1/1/11 - 12/31/11

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

(b) Prices represent weighted average prices.

Results of Operations

The following table presents selected volume and price information for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net production volumes:				
Oil (MBbl)	1,831	899	3,518	1,786
Natural gas (MMcf)	5,414	3,346	10,369	6,451
Total (MBoe)	2,733	1,457	5,246	2,861
Average daily production volumes:				
Oil (Bbl)	20,121	9,879	19,436	9,813
Natural gas (Mcf)	59,495	36,769	57,287	35,445
Total (Boe)	30,037	16,007	28,984	15,721
Average prices:				
Oil, without hedges (Bbl)	$ 55.44	$121.00	$ 47.32	$107.39
Oil, with hedges[(a)] (Bbl)	$ 55.44	$106.13	$ 47.32	$ 95.87
Natural gas, without hedges (Mcf)	$ 4.77	$ 12.52	$ 4.52	$ 11.33
Natural gas, with hedges[(a)] (Mcf)	$ 4.77	$ 12.54	$ 4.52	$ 11.30
Total, without hedges (Boe)	$ 46.59	$103.42	$ 40.67	$ 92.59
Total, with hedges[(a)] (Boe)	$ 46.59	$ 94.29	$ 40.67	$ 85.32

(a) These prices do not reflect the cash receipts/payments related to the oil and natural gas derivatives that were not designated as hedges and are reflected in loss on derivatives not designated as hedges in our statements of operations. If the cash receipts/payments related to the oil and natural gas derivatives that were not designated as hedges were included in our oil and natural gas sales our oil and natural gas prices would be as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Oil (Bbl)	$ 67.36	$ 92.86	$ 63.36	$ 86.93
Natural gas (Mcf)	$ 5.38	$ 12.40	$ 5.08	$ 11.23
Total (Boe)	$ 55.78	$ 85.78	$ 52.53	$ 79.59

The presentation above provides the full effect of our oil and natural gas derivatives program without consideration for the financial presentation of the cash receipts/payments on the oil and natural gas derivatives.

Table of Contents

Three months ended June 30, 2009, compared to three months ended June 30, 2008

Oil and natural gas revenues. Revenue from oil and natural gas operations was $127.3 million for the three months ended June 30, 2009, a decrease of $10.1 million (7 percent) from $137.4 million for the three months ended June 30, 2008. This decrease was primarily due to substantial decreases in realized oil and natural gas prices, offset by increased production (i) as a result of the acquisition of the Henry Properties on July 31, 2008 and (ii) due to successful drilling efforts during 2008 and 2009. Specifically the:

average realized oil price (after giving effect to hedging activities) was $55.44 per Bbl during the three months ended June 30, 2009, a decrease of 48 percent from $106.13 per Bbl during the three months ended June 30, 2008;

total oil production was 1,831 MBbl for the three months ended June 30, 2009, an increase of 932 MBbl (104 percent) from 899 MBbl for the three months ended June 30, 2008;

average realized natural gas price (after giving effect to hedging activities) was $4.77 per Mcf during the three months ended June 30, 2009, a decrease of 62 percent from $12.54 per Mcf during the three months ended June 30, 2008;

total natural gas production was 5,414 MMcf for the three months ended June 30, 2009, an increase of 2,068 MMcf (62 percent) from 3,346 MMcf for the three months ended June 30, 2008;

average realized barrel of oil equivalent price (after giving effect to hedging activities) was $46.59 per Boe during the three months ended June 30, 2009, a decrease of 51 percent from $94.29 per Boe during the three months ended June 30, 2008; and

total production was 2,733 MBoe for the three months ended June 30, 2009, an increase of 1,276 MBoe (88 percent) from 1,457 MBoe for the three months ended June 30, 2008.

Hedging activities. The oil and natural 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 in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our capital budget and expenditure plans and (iii) support the economics associated with acquisitions.

Currently, we do not designate our derivative instruments to qualify for hedge accounting. Accordingly, we reflect the changes in the fair value of our derivative instruments in the statements of operations as (gain) loss on derivatives not designated as hedges. All of our remaining hedges that historically qualified or were dedesignated from hedge accounting were settled in 2008.

The following is a summary of the effects of commodity hedges that qualify for hedge accounting treatment for the three months ended June 30, 2008:

	Oil Hedges Three Months Ended June 30, 2008	Natural Gas Hedges Three Months Ended June 30, 2008
Hedging revenue increase (decrease) (in thousands)	$ (13,367)	$ 74
Hedged volumes (Bbls and MMBtus, respectively)	236,000	1,228,000
Hedged revenue increase (decrease) per hedged volume	$ (56.64)	$ 0.06

44

Table of Contents

Production expenses. The following tables provide the components of our total oil and natural gas production costs for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,			
	2009		2008	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 15,726	$ 5.75	$ 9,296	$ 6.38
Taxes:				
Ad valorem	989	0.36	518	0.36
Production	9,090	3.33	12,030	8.26
Workover costs	12		135	0.09
Total oil and gas production expenses	$ 25,817	$ 9.44	$ 21,979	$ 15.09

Among the cost components of production expenses, in general, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

The lease operating expenses during the second quarter of 2008 include approximately $1.2 million ($0.82 per Boe) of costs that were associated with activity that occurred in the first quarter of 2008.

Lease operating expenses were $15.7 million ($5.75 per Boe) for the three months ended June 30, 2009, an increase of $6.4 million (69 percent) from $9.3 million ($6.38 per Boe) for the three months ended June 30, 2008. The total increase, taking into consideration details in the preceding paragraph, in lease operating expenses is due to (i) the wells acquired in the Henry Properties acquisition, which increased the absolute amount because those wells have a higher per unit cost as compared to our historical per unit cost and (ii) our wells successfully drilled and completed in 2008 and 2009.

Ad valorem taxes have increased primarily as a result of the Henry Properties acquisition, which were highly concentrated in Texas, a state which has a higher ad valorem rate than New Mexico, where substantially all of our properties prior to the acquisition were located.

Production taxes per unit of production were $3.33 per Boe during the three months ended June 30, 2009, a decrease of 60 percent from $8.26 per Boe during the three months ended June 30, 2008. The decrease is directly related to the decrease in commodity prices offset by the increase in oil and natural gas revenues related to increased volumes. Over the same period, our Boe prices (before the effects of hedging) decreased 55 percent.

Workover expenses were approximately $0.01 million and $0.1 million for the three months ended June 30, 2009 and 2008, respectively. The 2008 amounts related primarily to workovers in Andrews County, Texas and Lea County, New Mexico.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,	
(in thousands)	**2009**	**2008**
Geological and geophysical	$ 448	$ 424
Exploratory dry holes	445	(19)
Leasehold abandonments and other	531	318
Total exploration and abandonments	$ 1,424	$ 723

Table of Contents

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 June 30, 2009, was comparable to the three months ended June 30, 2008.

During the three months ended June 30, 2009, we wrote-off two unsuccessful exploratory wells in our Texas Permian area.

For the three months ended June 30, 2009, we recorded approximately $0.5 million of leasehold abandonments, which relates primarily to the write-off of a non-core prospect in New Mexico. For the three months ended June 30, 2008, we recorded $0.3 million of leasehold abandonments, which were primarily related to non-core prospects in Chaves County, New Mexico and Crane County, Texas.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,			
	2009		2008	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 51,218	$ 18.74	$ 21,584	$ 14.81
Depreciation of other property and equipment	796	0.29	426	0.29
Amortization of intangible asset operating rights	388	0.14		
Total depletion, depreciation and amortization	$ 52,402	$ 19.17	$ 22,010	$ 15.10
Crude oil price used to estimate proved oil reserves at period end	$ 66.25		$ 136.50	
Natural gas price used to estimate proved gas reserves at period end	$ 3.72		$ 13.10	

Depletion of proved oil and natural gas properties was $51.2 million ($18.74 per Boe) for the three months ended June 30, 2009, an increase of $29.6 million from $21.6 million ($14.81 per Boe) for the three months ended June 30, 2008. The increase in depletion expense, on a total and a per Boe basis, was primarily due to (i) the Henry Properties acquisition, for which the depletion rate was higher than that of our historical assets, (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2008 and 2009 and (iii) the decrease in the oil and natural gas prices between the years utilized to determine proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Henry Properties acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due to downward adjustments to the economically recoverable resource potential associated with declines in commodity prices and well performance, we recognized a non-cash charge against earnings of $4.5 million, which was primarily attributable to non-core natural gas related properties in Eddy and Lea Counties, New Mexico. For the three months ended June 30, 2008, we recognized a non-cash charge against earnings of $0.05 million, which was primarily attributable to a non-core lease located in Lea County, New Mexico.

Table of Contents

General and administrative expenses. The following table provides components of our general and administrative expenses for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,			
	2009		2008	
(in thousands, except per unit amounts)	Amount	Per Boe	Amount	Per Boe
General and administrative expenses recurring	$ 12,025	$ 4.40	$ 7,121	$ 4.89
Non-recurring bonus paid to former Henry Entities employees	2,750	1.01		
Non-cash stock-based compensation stock options	885	0.32	1,262	0.87
Non-cash stock-based compensation restricted stock	1,303	0.48	468	0.32
Less: Third-party operating fee reimbursements	(2,791)	(1.02)	(265)	(0.18)
Total general and administrative expenses	$ 14,172	$ 5.19	$ 8,586	$ 5.90

General and administrative expenses were $14.2 million ($5.19 per Boe) for the three months ended June 30, 2009, an increase of $5.6 million (65 percent) from $8.6 million ($5.90 per Boe) for the three months ended June 30, 2008. The increase in general and administrative expenses during the three months ended June 30, 2009 over 2008 was primarily due to (i) the non-recurring bonus paid to former Henry Entities employees, (ii) an increase in non-cash stock-based compensation for both stock options and restricted stock awards and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

In connection with the Henry Entities acquisition, we agreed to pay certain of our employees, who were formerly Henry Entities employees, a predetermined bonus amount, in addition to the compensation we pay these employees, over the next two years. Since these employees will earn this bonus over the next two years, we are reflecting the cost in our general and administrative costs as non-recurring, as it is not controlled by us. See Note K of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information related to this bonus.

We earn reimbursements as operator of certain oil and natural gas properties in which we own interests. As such, we earned reimbursements of $2.8 million and $0.3 million during the three months ended June 30, 2009 and 2008, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is directly related to the Henry Properties acquisition, as we own a lower working interest in these operated properties compared to our historical property base, so we receive a larger third-party reimbursement as compared to our historical property base.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to buy a portion of our oil affected as a result of the New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount due from this purchaser of approximately $1.8 million as of June 30, 2008, and are pursuing our claim in the bankruptcy proceedings.

Loss on derivatives not designated as hedges. During the three months ended June 30, 2007, we determined that all of our natural gas commodity derivative contracts no longer qualified as hedges. Because we no longer considered these hedges to be highly effective, we discontinued hedge accounting for those existing hedges, prospectively, and during the period the hedges became ineffective. In addition, for our new commodity and interest rate derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period. All amounts previously recorded in accumulated other comprehensive income were reclassified to earnings prior to 2009.

The following table sets forth the cash receipts for settlements and the non-cash mark-to-market adjustment for the derivative contracts not designated as hedges for the three months ended June 30, 2009 and 2008:

	Three Months Ended June 30,	
(in thousands)	**2009**	**2008**
Cash payments (receipts):		
Commodity derivatives oil	$ (21,828)	$ 11,929
Commodity derivatives natural gas	(3,292)	472
Financial derivatives interest	779	
Mark-to-market (gain) loss:		
Commodity derivatives oil	105,062	82,951
Commodity derivatives natural gas	4,312	7,104
Financial derivatives interest	(3,427)	
Loss on derivatives not designated as hedges	$ 81,606	$ 102,456

Interest expense. Interest expense was $6.2 million for the three months ended June 30, 2009, an increase of $2.3 million from $3.9 million for the three months ended June 30, 2008. The weighted average interest rate for the three months ended June 30, 2009 and 2008 was 2.9% and 4.9%, respectively. The weighted average debt balance during the three months ended June 30, 2009 and 2008 was approximately $680.0 million and $302.1 million, respectively.

The increase in weighted average debt balance during the three months ended June 30, 2009 was due primarily to borrowings in July 2008 for the acquisition of the Henry Properties. The increase in interest expense is due to an increase in the weighted average debt balance offset by a decrease in the weighted average interest rate. The decrease in the weighted average interest rate is primarily due to an improvement in market interest rates.

Income tax provisions. We recorded an income tax benefit of $25.7 million and $9.2 million for the three months ended June 30, 2009 and 2008, respectively. The effective income tax rate for the three months ended June 30, 2009 and 2008 was 43.6 percent and 38.9 percent, respectively. The higher effective tax rate in 2009 compared to 2008 is primarily due to the estimated annual 2009 permanent tax differences compared to the related current estimated pre-tax book income.

Six months ended June 30, 2009, compared to six months ended June 30, 2008

Oil and natural gas revenues. Revenue from oil and natural gas operations was $213.3 million for the six months ended June 30, 2009, a decrease of $30.8 million (13 percent) from $244.1 million for the six months ended June 30, 2008. This decrease was primarily due to substantial decreases in realized oil and natural gas prices, offset by increased production (i) as a result of the acquisition of the Henry Properties on July 31, 2008 and (ii) due to successful drilling efforts during 2008 and 2009. Specifically the:

average realized oil price (after giving effect to hedging activities) was $47.32 per Bbl during the six months ended June 30, 2009, a decrease of 51 percent from $95.87 per Bbl during the six months ended June 30, 2008;

total oil production was 3,518 MBbl for the six months ended June 30, 2009, an increase of 1,732 MBbl (97 percent) from 1,786 MBbl for the six months ended June 30, 2008;

average realized natural gas price (after giving effect to hedging activities) was $4.52 per Mcf during the six months ended June 30, 2009, a decrease of 60 percent from $11.30 per Mcf during the six months ended June 30, 2008;

total natural gas production was 10,369 MMcf for the six months ended June 30, 2009, an increase of 3,918 MMcf (61 percent) from 6,451 MMcf for the six months ended June 30, 2008;

average realized barrel of oil equivalent price (after giving effect to hedging activities) was $40.67 per Boe during the six months ended June 30, 2009, a decrease of 52 percent from $85.32 per Boe during the six months ended June 30, 2008; and total production was 5,246 MBoe for the six months ended June 30, 2009, an increase of 2,385 MBoe (83 percent) from 2,861 MBoe for the six months ended June 30, 2008.

Hedging activities. The oil and natural 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 in order to (i) reduce the effect of the volatility of price changes on the commodities we produce and sell, (ii) support our capital budget and expenditure plans and (iii) support the economics associated with acquisitions.

Currently, we do not designate our derivative instruments to qualify for hedge accounting. Accordingly, we reflect the changes in the fair value of our derivative instruments in the statements of operations as (gain) loss on derivatives not designated as hedges. All of our remaining hedges that historically qualified or were dedesignated from hedge accounting were settled in 2008.

The following is a summary of the effects of commodity hedges that qualify for hedge accounting treatment for the six months ended June 30, 2008:

	Oil Hedges Six Months Ended June 30, 2008	Natural Gas Hedges Six Months Ended June 30, 2008
Hedging revenue increase (decrease) (in thousands)	$ (20,573)	$ (222)
Hedged volumes (Bbls and MMBtus, respectively)	473,000	2,457,000
Hedged revenue increase (decrease) per hedged volume	$ (43.49)	$ (0.09)

Production expenses. The following tables provide the components of our total oil and natural gas production costs for the six months ended June 30, 2009 and 2008:

	Six Months Ended June 30,			
	2009		2008	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 32,294	$ 6.16	$ 16,238	$ 5.68
Taxes:				
Ad valorem	2,491	0.47	1,006	0.35
Production	15,365	2.93	21,108	7.38
Workover costs	433	0.08	522	0.18
Total oil and gas production expenses	$ 50,583	$ 9.64	$ 38,874	$ 13.59

Among the cost components of production expenses, in general, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $32.3 million ($6.16 per Boe) for the six months ended June 30, 2009, an increase of $16.1 million (99 percent) from $16.2 million ($5.68 per Boe) for the six months ended June 30, 2008. The increase in lease operating expenses is due to (i) the wells acquired in the Henry Properties acquisition, which increased the absolute and per unit amount because those wells have a higher per unit cost as compared to our historical per unit cost and (ii) our wells successfully drilled and completed in 2008 and 2009.

Ad valorem taxes have increased primarily as a result of the Henry Properties acquisition, which were highly concentrated in Texas, a state which has a higher ad valorem rate than New Mexico, where substantially all of our properties prior to the acquisition were located.

Production taxes per unit of production were $2.93 per Boe during the six months ended June 30, 2009, a decrease of 60 percent from $7.38 per Boe during the six months ended June 30, 2008. The decrease is directly related to the decrease in commodity prices offset by the increase in oil and natural gas revenues related to increased volumes. Over the same period, our Boe prices (before the effects of hedging) decreased 56 percent.

Workover expenses were approximately $0.4 million and $0.5 million for the six months ended June 30, 2009 and 2008, respectively. The 2009 and 2008 amounts related primarily to workovers in Andrews County, Texas.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the six months ended June 30, 2009 and 2008:

	Six Months Ended June 30,	
(in thousands)	**2009**	**2008**
Geological and geophysical	$ 1,125	$ 2,317
Exploratory dry holes	1,866	(1)
Leasehold abandonments and other	4,428	1,148
Total exploration and abandonments	$ 7,419	$ 3,464

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, during the six months ended June 30, 2009, was $1.1 million, a decrease of $1.2 million from $2.3 million for the six months ended June 30, 2008. This decrease is primarily attributable to a comprehensive seismic survey on our New Mexico shelf properties which was initiated in December 2007 and completed in 2008.

During the six months ended June 30, 2009, we wrote-off an unsuccessful exploratory well in our Arkansas emerging play and two unsuccessful exploratory wells in our Texas Permian area.

For the six months ended June 30, 2009, we recorded approximately $4.4 million of leasehold abandonments, which relate primarily to the write-off of four non-core prospects in New Mexico and three non-core prospects in Texas. For the six months ended June 30, 2008, we recorded $1.1 million of leasehold abandonments, which were primarily related to non-core prospects in Chaves and Eddy Counties, New Mexico and Andrews and Crane Counties, Texas.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the six months ended June 30, 2009 and 2008:

	Six Months Ended June 30,			
	2009		2008	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 100,995	$ 19.25	$ 42,510	$ 14.86
Depreciation of other property and equipment	1,374	0.26	784	0.27
Amortization of intangible asset operating rights	781	0.15		
Total depletion, depreciation and amortization	$ 103,150	$ 19.66	$ 43,294	$ 15.13
Crude oil price used to estimate proved oil reserves at period end	$ 66.25		$ 136.50	
Natural gas price used to estimate proved gas reserves at period end	$ 3.72		$ 13.10	

Depletion of proved oil and natural gas properties was $101.0 million ($19.25 per Boe) for the six months ended June 30, 2009, an increase of $58.5 million from $42.5 million ($14.86 per Boe) for the six months ended June 30, 2008. The increase in depletion expense, on a total and per Boe basis, was primarily due to (i) the Henry Properties acquisition, for which the depletion rate was higher than that of our historical assets, (ii) capitalized costs associated with new wells that were successfully drilled and completed in 2008 and 2009 and (iii) the decrease in the oil and natural gas prices between the years utilized to determine proved reserves.

The amortization of the intangible asset is a result of the value assigned to the operating rights that we acquired in the Henry Properties acquisition. The intangible asset is currently being amortized over an estimated life of approximately 25 years.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due to downward adjustments to the economically recoverable resource potential associated with declines in commodity prices and well performance, we recognized a non-cash charge against earnings of $8.6 million, which was primarily attributable to non-core natural gas related properties in Eddy and Lea Counties, New Mexico. For the six months ended June 30, 2008, we recognized a non-cash charge against earnings of $0.07 million, which was primarily attributable to a non-core lease located in Eddy and Lea Counties, New Mexico.

General and administrative expenses. The following table provides components of our general and administrative expenses for the six months ended June 30, 2009 and 2008:

	Six Months Ended June 30,			
	2009		2008	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses recurring	$ 21,939	$ 4.18	$ 13,741	$ 4.80
Non-recurring bonus paid to former Henry Entities employees	5,311	1.01		
Non-cash stock-based compensation stock options	1,913	0.36	2,167	0.76
Non-cash stock-based compensation restricted stock	2,200	0.42	862	0.30
Less: Third-party operating fee reimbursements	(5,445)	(1.04)	(504)	(0.17)
Total general and administrative expenses	$ 25,918	$ 4.93	$ 16,266	$ 5.69

General and administrative expenses were $25.9 million ($4.93 per Boe) for the six months ended June 30, 2009, an increase of $9.6 million (59 percent) from $16.3 million ($5.69 per Boe) for the six months ended June 30, 2008. The increase in general and administrative expenses during the six months ended June 30, 2009 over 2008 was primarily due to (i) the non-recurring bonus paid to former Henry Entities employees, (ii) an increase in non-cash stock-based compensation for both stock options and restricted stock awards and (iii) an increase in the number of employees and related personnel expenses, partially offset by an increase in third-party operating fee reimbursements.

In connection with the Henry Entities acquisition, we agreed to pay certain of our employees, who were formerly Henry Entities employees, a predetermined bonus amount, in addition to the compensation we pay these employees, over the next two years. Since these employees will earn this bonus over the next two years, we are reflecting the cost in our general and administrative costs as non-recurring, as it is not controlled by us. See Note K of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information related to this bonus.

We earn reimbursements as operator of certain oil and natural gas properties in which we own interests. As such, we earned reimbursements of $5.4 million and $0.5 million during the six months ended June 30, 2009 and 2008, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in this reimbursement is directly related to the Henry Properties acquisition, as we own a lower working interest in these operated properties compared to our historical property base, so we receive a larger third-party reimbursement as compared to our historical property base.

Bad debt expense. On May 20, 2008, we entered into a short-term purchase agreement with an oil purchaser to buy a portion of our oil affected as a result of the New Mexico refinery shut down due to repairs. On July 22, 2008, this purchaser declared bankruptcy. We fully reserved the receivable amount due from this purchaser of approximately $1.8 million as of June 30, 2008, and are pursuing our claim in the bankruptcy proceedings.

Loss on derivatives not designated as hedges. During the six months ended June 30, 2007, we determined that all of our natural gas commodity derivative contracts no longer qualified as hedges. Because we no longer considered these hedges to be highly effective, we discontinued hedge accounting for those existing hedges, prospectively, and during the period the hedges became ineffective. In addition, for our new commodity and interest rate derivative contracts entered into after August 2007, we chose not to designate any of these contracts as hedges. As a result, any changes in fair value and any cash settlements related to these contracts are recorded in earnings during the related period. All amounts previously recorded in accumulated other comprehensive income were reclassified to earnings prior to 2009.

The following table sets forth the cash receipts for settlements and the non-cash mark-to-market adjustment for the derivative contracts not designated as hedges for the six months ended June 30, 2009 and 2008:

	Six Months Ended June 30,	
(in thousands)	**2009**	**2008**
Cash payments (receipts):		
Commodity derivatives oil	$ (56,412)	$ 15,965
Commodity derivatives natural gas	(5,832)	422
Financial derivatives interest	779	
Mark-to-market (gain) loss:		
Commodity derivatives oil	144,099	88,900
Commodity derivatives natural gas	5,018	14,347
Financial derivatives interest	(1,000)	
Loss on derivatives not designated as hedges	$ 86,652	$ 119,634

Interest expense. Interest expense was $10.6 million for the six months ended June 30, 2009, an increase of $1.1 million from $9.5 million for the six months ended June 30, 2008. The weighted average interest rate for the six months ended June 30, 2009 and 2008 was 2.5% and 5.8%, respectively. The weighted average debt balance during the six months ended June 30, 2009 and 2008 was approximately $668.0 million and $313.3 million, respectively.

The increase in weighted average debt balance during the six months ended June 30, 2009 was due primarily to borrowings in July 2008 for the acquisition of the Henry Properties. The increase in interest expense is due to an increase in the weighted average debt balance offset by a decrease in the weighted average interest rate. The decrease in the weighted average interest rate is primarily due to an improvement in market interest rates.

Income tax provisions. We recorded an income tax benefit of $33.8 million and income tax expense of $5.2 million for the six months ended June 30, 2009 and 2008, respectively. The effective income tax rate for the six months ended June 30, 2009 and 2008 was 42.1 percent and 39.6 percent, respectively. The higher effective tax rate in 2009 compared to 2008 is primarily due to the estimated annual 2009 permanent tax differences compared to the related current estimated pre-tax book income.

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our Credit Facility, proceeds from the disposition of assets or alternative financing sources, as discussed in Capital resources below.

Oil and natural gas properties. Our capital expenditures on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the three months ended June 30, 2009 and 2008 totaled $96.4 million and $66.1 million, respectively, and $202.7 million and $121.3 million for the six months ended June 30, 2009 and 2008, respectively. These expenditures were primarily funded by cash flow from operations (including effects of derivative cash receipts/payments).

On November 6, 2008, our board of directors approved a capital budget for 2009 of up to approximately $500 million. The capital budget is predicated on funding it substantially within cash flow. In January 2009, in light of the drop in commodity prices, we took actions to reduce our capital activities to a level that would allow us to fund our capital expenditures substantially within our cash flow, which at the time resulted in estimated annual capital expenditures of approximately $300 million. Currently, based on current capital costs and commodity prices we estimate our capital expenditures to be approximately $400 million for 2009, which we believe we can substantially fund within our cash flow. We will continue to monitor our capital expenditures, at least on a quarterly basis, in relation to our cash flow and expect to adjust our activity and capital spending level based on changes in commodity prices and the cost of goods and services and other considerations.

Other than the purchase of leasehold acreage and other miscellaneous property interests, our 2009 capital 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 natural 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.

Although we cannot provide any assurance, we believe that our available cash and cash flows will be sufficient to fund our 2009 capital expenditures, as adjusted from time to time; however, we could also use our credit facility or other alternative financing sources 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, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances we would consider increasing or reallocating our 2009 capital budget.

Acquisitions. Our expenditures for acquisitions of proved and unproved properties during the three months ended June 30, 2009 and 2008 totaled $3.3 million and $0.5 million, respectively, and $3.6 million and $1.4 million for the six months ended June 30, 2009 and 2008, respectively. Included in previous acquisition amounts are adjustments to the purchase price allocation related to the acquisition of the Henry Properties of $0.4 million and $0.7 million for the three and six months ended June 30 , 2009, respectively. The Henry Properties acquisition in July 2008 was primarily funded by a private placement of our common stock and borrowings under our credit facility.

Contractual obligations. Our contractual obligations include long-term debt, operating lease obligations, drilling commitments (including commitments to pay day rates for drilling rigs), employment agreements, contractual bonus payments, derivative obligations and other liabilities. Since December 31, 2008, the material changes in our contractual obligations included a $30.0 million increase in outstanding long-term borrowings, a $148.1 million decrease in our net commodity derivative assets, and a $25.8 million decrease in our drilling commitments. See Note J of Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding our long-term debt and Item 3. Quantitative and Qualitative Disclosures About Market Risk for information regarding the interest on our long-term debt and information on changes in the fair value of our open derivative obligations during the three and six months ended June 30, 2009.

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

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our credit facility. We believe that funds from operating cash flows and our credit facility should be sufficient to meet both our short-term working capital requirements and our 2009 capital budget plans.

Cash flow from operating activities. Our net cash provided by operating activities was $118.2 million and $162.9 million for the six months ended June 30, 2009 and 2008, respectively. The decrease in operating cash flows during the six months ended June 30, 2009 over 2008 was principally due to (i) decreases in average realized oil and natural gas prices, offset by increased production, (ii) increases in oil and natural gas production costs and general and administrative expenses and (iii) uses of funds associated with working capital.

Cash flow used in investing activities. During the six months ended June 30, 2009 and 2008, we invested $223.9 million and $122.8 million, respectively, for additions to, and acquisitions of, oil and natural gas properties, inclusive of dry hole costs. Cash flows used in investing activities were substantially higher during the three months ended June 30, 2009 over 2008, due to an increase in our exploration and development activities, offset by the receipts/payments associated with derivatives not designated as hedges.

Cash flow from financing activities. Net cash provided by (used in) financing activities was $29.9 million and $(19.5) million for the six months ended June 30, 2009 and 2008, respectively. During the six months ended June 30, 2009, we had net borrowings of $30.0 million under our credit facility. During the six months ended June 30, 2008, we reduced our outstanding balance by $26.5 million on our credit facilities.

Our credit facility, as amended, and has a maturity date of July 31, 2013 (the Credit Facility). At June 30, 2009, we had letters of credit outstanding under the Credit Facility of approximately $25,000 and our availability to borrow additional funds was approximately $300 million. In April 2009, the lenders reaffirmed our $960 million borrowing base under the Credit Facility until the next scheduled borrowing base redetermination in October 2009. Between scheduled borrowing base redeterminations, we and, if requested by 66 2/3 percent of the lenders, the lenders, may each request one special redetermination.

Advances on the Credit Facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (3.25 percent at June 30, 2009) or (ii) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). At June 30, 2009, the interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 200 to 300 basis points and 112.5 to 212.5 basis points, respectively, per annum depending on the debt balance outstanding. At June 30, 2009, we pay commitment fees on the unused portion of the available borrowing base of 50 basis points per annum.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock (iv) common stock and (v) other securities. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time to time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our Credit Facility.

Financial markets. The current state of the financial markets is uncertain. There have been financial institutions that have (i) failed and been forced into government receivership, (ii) declared bankruptcy, (iii) been forced to seek additional capital and liquidity to maintain viability or (iv) merged. The United States and world economy is experiencing volatility, which is having an adverse impact on the financial markets.

At June 30, 2009, we had $300.0 million of available borrowing capacity under our Credit Facility. Even in light of the current volatility in the financial markets, we currently believe that the lenders under our Credit Facility have the ability to fund additional borrowings we may need for our business.

We currently pay floating rate interest under our Credit Facility and we are unable to predict, especially in light of the current uncertainty in the financial markets, whether we will incur increased interest costs due to rising interest rates. We have utilized the use of interest rate derivatives to mitigate the cost of rising interest rates, and we may enter into additional interest rate derivatives in the future. Additionally, we may issue fixed rate debt in the future to increase available borrowing capacity under our Credit Facility or to reduce our exposure to the volatility of interest rates.

In the current financial markets, we do not believe that we could refinance our Credit Facility and obtain comparable terms. Since our Credit Facility matures in July 2013, we have no immediate need to seek refinancing of our Credit Facility.

To the extent we need additional funds, beyond those available under our Credit Facility, to operate our business or make acquisitions we would have to pursue other financing sources. These sources could include issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock or (v) other securities. We may also sell assets. However, in light of the current financial market conditions there are no assurances that we could obtain additional funding, or if available, at what cost and terms.

Liquidity. Our principal sources of short-term liquidity are cash on hand and available borrowing capacity under our Credit Facility. At June 30, 2009, we had $3.1 million of cash on hand.

At June 30, 2009, the borrowing base under our credit facility was $960 million, which provided us with $300.0 million of available borrowing capacity. Our borrowing base is redetermined semi-annually, with the next redetermination occurring in October 2009. In addition to such semi-annual redeterminations, our lenders may request one additional redetermination during any twelve-month period. In general, redeterminations are based upon a number of factors, including commodity prices and reserve levels. Upon a redetermination, our borrowing base could be substantially reduced. In light of the current commodity prices and the state of the financial markets, there is no assurance that our borrowing base will not be reduced.

Book capitalization and current ratio. Our book capitalization at June 30, 2009 was $1,949.6 million, consisting of debt of $660.0 million and stockholders equity of $1,289.6 million. Our debt to book capitalization was 34 percent and 32 percent at June 30, 2009 and December 31, 2008, respectively. Our ratio of current assets to current liabilities was 0.76 to 1.00 at June 30, 2009 as compared to 1.03 to 1.00 at December 31, 2008.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that are beyond our ability to control or predict. During the three months ended

June 30, 2009, we received an average of $55.44 per barrel of oil and $4.77 per Mcf of natural gas before consideration of commodity derivative contracts compared to $121.00 per barrel of oil and $12.52 per Mcf of natural gas in the three months ended June 30, 2008. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. In a trend that began in 2004 and continued through the first six months of 2008, commodity prices for oil and natural gas increased significantly. The higher prices have led to increased activity in the industry and, consequently, rising costs. These cost trends have put pressure not only on our operating costs but also on capital costs. We expect these costs to continue to moderate during the remainder of 2009 as a result of the recent rapid diminution in prices for oil and natural gas from 2008 peaks.

Critical Accounting Policies, Practices and Estimates

Our historical consolidated financial statements and related notes to 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, impairment of long-lived assets and valuation of stock-based compensation. 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 June 30, 2009. 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, 2008, filed with the SEC on February 27, 2009.

Recent Accounting Pronouncements and Developments

Recent accounting pronouncements. In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 141(R), *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. SFAS No. 141(R) 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. We adopted SFAS No. 141(R) effective January 1, 2009. There has been no impact on our consolidated financial statements, as we have not entered into any significant business combinations during 2009.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements an amendment of ARB No. 51* (SFAS No. 160). 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. We adopted SFAS No. 160 effective January 1, 2009, with no impact on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities* (SFAS No. 161), which amends and expands the interim and annual disclosure requirements of 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 adopted SFAS No. 161 effective January 1, 2009, with no significant impact on our consolidated financial statements, other than additional disclosures which are set forth in Notes H and I of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited).

In April 2008, the FASB issued FASB Staff Position (FSP) No. SFAS 142-3, *Determination of the Useful Life of Intangible Assets* (FSP SFAS No. 142-3). FSP SFAS No. 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142, *Goodwill and Other Intangible Assets* (SFAS No. 142). The intent of FSP SFAS No. 142-3 is to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141R and other applicable accounting literature. FSP SFAS No. 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008 and must be applied prospectively to intangible assets acquired after the effective date. We adopted FSP SFAS No. 142-3 effective January 1, 2009, with no significant impact on our consolidated financial statements.

In May 2008, the FASB issued SFAS No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 162), which identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with generally accepted accounting principles (GAAP) in the United States of America. SFAS No. 162 arranges these sources of GAAP in a hierarchy for users to apply accordingly. This statement became effective for us on November 15, 2008. The adoption of SFAS No. 162 did not have a significant impact on our consolidated financial statements. In June 2009, this statement was replaced with SFAS No. 168, *The FASB Accounting Standards Codification* (Codification) *and the Hierarchy of Generally Accepted Accounting Principles* (SFAS No. 168). Once the Codification is in effect, all of its content will carry the same level of authority, effectively superseding SFAS No. 162. In other words, the GAAP hierarchy will be modified to include only two levels of GAAP: authoritative and nonauthoritative. SFAS No. 168 is effective for financial statements issued for interim and annual periods ending after September 15, 2009. We do not expect the adoption of SFAS No. 168 to have an impact on our consolidated financial statements.

In June 2008, the FASB issued FSP No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, (FSP EITF 03-6-1) which provides that unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and, therefore, need to be included in the earnings allocation in computing earnings per share under the two class method. FSP EITF 03-6-1 was effective for us on January 1, 2009. There was no impact on our consolidated financial statements.

In April 2009, the FASB issued FSP SFAS No. 141(R)-1, *Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies.* This FSP amends and clarifies SFAS No. 141(R) to address application issues raised by preparers, auditors, and members of the legal profession on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. This FSP is effective for assets or liabilities arising from contingencies in business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We have not made any acquisitions during 2009, and as such, the adoption of this statement on January 1, 2009 did not have a significant impact.

In April 2009, the FASB issued FSP SFAS No. 107-1 and APB Opinion No. 28-1, *Interim Disclosures about Fair Value of Financial Instrument* (FSP SFAS No. 107-1). This FSP amends FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments,* to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. This FSP also amends APB Opinion No. 28, *Interim Financial Reporting,* to require those disclosures in summarized financial information at interim reporting periods. This FSP is effective for interim reporting periods ending after June 15, 2009. This FSP does not require disclosures for earlier periods presented for comparative purposes at initial adoption. In periods after initial adoption, this FSP requires comparative disclosures only for periods ending after initial adoption. As of June 15, 2009, we adopted the provisions of FSP SFAS No. 107-1 related to the fair value of financial instruments. The adoption of the provisions of FSP SFAS No. 107-1 did not have a material effect on our financial condition or results of operations. See Note H for additional disclosures required by FSP SFAS No. 107-1.

In April 2009, the FASB issued FSP SFAS No. 157-4, *Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly* (FSP SFAS No. 157-4). This FSP:

Affirms that the objective of fair value when the market for an asset is not active is the price that would be received to sell the asset in an orderly transaction;

Clarifies and includes additional factors for determining whether there has been a significant decrease in market activity for an asset when the market for that asset is not active;

Eliminates the proposed presumption that all transactions are distressed (not orderly) unless proven otherwise. The FSP instead requires an entity to base its conclusion about whether a transaction was not orderly on the weight of the evidence;

Includes an example that provides additional explanation on estimating fair value when the market activity for an asset has declined significantly;

Requires an entity to disclose a change in valuation technique (and the related inputs) resulting from the application of the FSP and to quantify its effects, if practicable; and

Applies to all fair value measurements when appropriate.

FSP SFAS No. 157-4 must be applied prospectively and retrospective application is not permitted. FSP SFAS No. 157-4 is effective for interim and annual periods ending after June 15, 2009. As of June 15, 2009, we adopted the provisions of FSP SFAS No. 157-4 related to assets and liabilities that are measured at fair value on a recurring and nonrecurring basis. The adoption of the provisions of FSP SFAS No. 157-4 did not have a material effect on our financial condition or results of operations. See Note H of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding our adoption of FSP SFAS No. 157-4.

In May 2009, the FASB issued SFAS No. 165, *Subsequent Events* (SFAS No. 165) which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date, but before financial statements are issued or are available to be issued. In particular, SFAS No. 165 sets forth:

The period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements;

The circumstances under which a reporting entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and

The disclosures that a reporting entity should make about events or transactions that occurred after the balance sheet date.

In accordance with this Statement, a reporting entity should apply the requirements to interim or annual financial periods ending after June 15, 2009. See Note P of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited).

In June 2009, the FASB issued SFAS No. 166, *Accounting for Transfers of Financial Assets* (SFAS No. 166), which amends SFAS No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities*. This statement improves the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial reports about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor s continuing involvement in transferred financial assets. SFAS No. 166 must be applied as of the beginning of each reporting entity s first annual reporting period that begins after November 15, 2009, for interim periods within that first annual reporting period and for interim and annual reporting periods thereafter. Earlier application is prohibited. SFAS No. 166 must be applied to transfers occurring on or after the effective date. We do not expect the adoption of SFAS No. 166 to have an impact on our consolidated financial statements.

Recent developments in reserves reporting. In December 2008, the United States Securities and Exchange Commission (the SEC) released Final Rule, *Modernization of Oil and Gas Reporting* (the Reserve Ruling). The Reserve Ruling revises oil and gas reporting disclosures. The Reserve Ruling permits the use of new technologies to determine proved reserves estimates if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volume estimates. The Reserve Ruling will also allow, but not require, companies to disclose their probable and possible reserves to investors in documents filed with the SEC. In addition, the new disclosure requirements require companies to: (i) report the independence and qualifications of its reserves preparer or auditor; (ii) file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit; and (iii) report oil and gas reserves using an average price based upon the prior 12-month period rather than a year-end price. The Reserve Ruling becomes effective for fiscal years ending on or after December 31, 2009. We are currently assessing the impact that adoption of the provisions of the Reserve Ruling will have on our financial position, results of operations and disclosures.

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, 2008.

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. The following quantitative and qualitative information is provided about financial instruments to which we are a party at June 30, 2009, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity 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. 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. In this manner, we reduce credit risk.

Commodity price risk. We are exposed to market risk as the prices of 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 net income and the value of our common stock. At June 30, 2009, the net unrealized asset on our commodity price risk management contracts was $24.3 million. An average increase in the commodity price of $10.00 per barrel of oil and $1.00 per Mcf for natural gas from the commodity prices at June 30, 2009, would have resulted in a net unrealized liability on our commodity price risk management contracts, as reflected on our consolidated balance sheet at June 30, 2009, of approximately $81.0 million.

At June 30, 2009, we had (i) an oil price collar and oil price swaps that settle on a monthly basis covering future oil production from July 1, 2009 through December 31, 2012 and (ii) a natural gas price swap, natural gas price collars and natural gas basis swaps covering future natural gas production from July 1, 2009 to December 31, 2011, see Note I of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information on the commodity derivative contracts. The average NYMEX oil futures price and average NYMEX natural gas futures prices for the three months ended June 30, 2009, was $59.83 per Bbl and $3.80 per MMBtu, respectively. At August 3, 2009, the NYMEX oil futures price and NYMEX natural gas futures price was $71.58 per Bbl and $4.03 per MMBtu, respectively. The decrease in oil and natural gas prices, should it continue during 2009, should increase the fair value asset of our commodity derivative contracts from their recorded balance at June 30, 2009. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as unrealized gains or losses. The potential increase in fair value asset would be recorded in earnings as unrealized gains. However, an increase in the average NYMEX oil and natural gas futures price above those at June 30, 2009 would result in an decrease in fair value asset and unrealized losses in earnings. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity 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. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. 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 credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base.

Table of Contents

At June 30, 2009, we had interest rate swaps on $300 million of notional principal that fixed the LIBOR interest rate (does not include the interest rate margins discussed above) at 1.90 percent for the three years beginning in May 2009. An average decrease in future interest rates of 25 basis points from the future rate at June 30, 2009, would have resulted in a net unrealized liability on our interest rate risk management contracts, as reflected on our consolidated balance sheet at June 30, 2009, of approximately $2.1 million.

We had total indebtedness of $660 million outstanding under our credit facility at June 30, 2009. The impact of a 1 percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $6.6 million.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during 2009. During 2009, we were party to commodity derivative instruments. See Note I of the Condensed Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited) for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the six months ended June 30, 2009:

	Derivative Instruments Net Assets (Liabilities) [(a)]		
(in thousands)	**Commodities**	**Interest Rate**	**Total**
Fair value of contracts outstanding at December 31, 2008	$ 173,523	$ (1,083)	$ 172,440
Changes in fair values [(b)]	(86,873)	221	(86,652)
Contract maturities	(62,244)	779	(61,465)
Fair value of contracts outstanding at June 30, 2009	$ 24,406	$ (83)	$ 24,323

(a) Represents the fair values of open derivative contracts subject to market risk.

(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Table of Contents

Item 4. Controls and Procedures

Evaluation of disclosure controls and procedures. The Company s management, with the participation of its principal executive officer and principal financial officer, have evaluated, as required by Rule 13a-15(b) under the Exchange Act, the Company s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of the end of the period covered by this report. Based on that evaluation, the Company s principal executive officer and principal financial officer concluded that the design and operation of the Company s disclosure controls and procedures are effective in ensuring that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms.

Changes in internal control over financial reporting. There have been no changes in the Company s internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the Company s last fiscal quarter that have materially affected or are reasonably likely to materially affect the Company s internal controls over financial reporting.

Table of Contents

PART II OTHER INFORMATION

Item 1. Legal Proceedings

We are party to the legal proceedings described under Legal actions in Note K of Notes to Consolidated Financial Statements included in Item 1. Consolidated Financial Statements (Unaudited). We are also party to other proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the amount of the liability, if any, ultimately incurred with respect to such proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations.

Item 1A. Risk Factors

In addition to the other information set forth in this Report, you should carefully consider the risks discussed in the Company s Annual Report on Form 10-K for the year ended December 31, 2008, under the headings Item 1. Business Competition, Marketing Arrangements and Applicable Laws and Regulations, Item 1A. Risk Factors and Item 7A. Quantitative and Qualitative Disclosures About Market Risk, which risks could materially affect the Company s business, financial condition or future results. Except for the risk factors set forth below, there have been no material changes in the Company s risk factors from those described in its Annual Report on Form 10-K for the year ended December 31, 2008.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

President Obama s Proposed Fiscal Year 2010 Budget includes proposed legislation that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities, and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes will be enacted or how soon any such changes could become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could eliminate or otherwise limit certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively impact our financial condition and results of operations.

The adoption of climate change legislation by Congress could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On June 26, 2009, the U.S. House of Representatives approved adoption of the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey cap-and-trade legislation or ACESA. The purpose of ACESA is to control and reduce emissions of greenhouse gases, or GHGs, in the United States. GHGs are certain gases, including carbon dioxide and methane, that may be contributing to warming of the Earth s atmosphere and other climatic changes. ACESA would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. Under ACESA, most sources of GHG emissions would be required to obtain GHG emission allowances corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet ACESA s overall emission reduction goals. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of ACESA will be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas.

The U.S. Senate has begun work on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. President Obama has indicated that he is in support of the adoption of legislation to control and reduce emissions of GHGs through an emission allowance permitting system that results in fewer allowances being issued each year but that allows parties to buy, sell and trade allowances as needed to fulfill their GHG emission obligations.

Although it is not possible at this time to predict whether or when the Senate may act on climate change legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted to restrict or reduce emissions of GHGs could require us to incur increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce.

Table of Contents

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to hedge risks associated with our business.

Congress is currently considering legislation to impose restrictions on certain transactions involving derivatives, which could affect the use of derivatives in hedging transactions. ACESA contains provisions that would prohibit private energy commodity derivative and hedging transactions. ACESA would expand the power of the Commodity Futures Trading Commission, or CFTC, to regulate derivative transactions related to energy commodities, including oil and natural gas, and to mandate clearance of such derivative contracts through registered derivative clearing organizations. Under ACESA, the CFTC s expanded authority over energy derivatives would terminate upon the adoption of general legislation covering derivative regulatory reform. The CFTC is conducting hearings to determine whether to set limits on trading and positions in commodities with finite supply, particularly energy commodities, such as crude oil, natural gas and other energy products. The CFTC also is evaluating whether position limits should be applied consistently across all markets and participants. In addition, the Treasury Department recently has indicated that it intends to propose legislation to subject all over-the-counter, or OTC, derivative dealers and all other major OTC derivatives market participants to substantial supervision and regulation, including by imposing conservative capital and margin requirements and strong business conduct standards. Derivatives contracts that are not cleared through central clearinghouses and exchanges may be subject to substantially higher capital and margin requirements. Although it is not possible at this time to predict whether or when the Senate may act on derivatives legislation or how any bill approved by the Senate would be reconciled with ACESA, any laws or regulations that may be adopted that subject us to additional capital or margin requirements relating to, or additional restrictions on, our trading and commodity positions could have an adverse impact on our ability to hedge risks associated with our business.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Congress is currently considering legislation to amend the federal Safe Drinking Water Act to require the disclosure of chemicals used by the oil and gas industry in the hydraulic fracturing process. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate oil and natural gas production. Sponsors of bills currently pending before the Senate and House of Representatives have asserted that chemicals used in the fracturing process may be impacting drinking water supplies. The proposed legislation would require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process are impairing groundwater or causing other damage. In addition, these bills, if adopted, could establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers

Period	Total number of shares withheld (1)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
April 1, 2009 - April 30, 2009		$		
May 1, 2009 - May 31, 2009		$		

June 1, 2009 - June 30, 2009	6,199	$	31.14

(1) Represents shares that were withheld by the Company to satisfy tax withholding obligations of certain executive officers that arose upon the lapse of restrictions on restricted stock.

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

The 2009 Annual Meeting of Stockholders of Concho Resources Inc. (Annual Meeting) was held on June 2, 2009, in Midland, Texas for the following purposes: (i) to elect two Class II directors, each for a term of three years; (ii) to ratify the Audit Committee of the Board of Directors selection of Grant Thornton LLP as the independent registered public accounting firm of the Company for the fiscal year ending December 31, 2009; and (iii) to transact such other business as may properly come before the Annual Meeting or any adjournments or postponements thereof.

Proxies for the Annual Meeting were solicited by the Board pursuant to Regulation 14A under the Securities Exchange Act of 1934 as amended and there was no solicitation in opposition to the Board s nominees for director.

Each of the nominees for director was duly elected, with votes as follows:

Nominee	**Shares for**	**Shares withheld**
Steven L. Beal	75,380,942	529,097
Tucker S. Bridwell	74,692,704	1,217,335

The appointment of Grant Thornton LLP, independent public accountants, as the Company s auditors for the year ending December 31, 2009, was ratified by the Company s stockholders by the following vote: 74,781,613 for; 1,122,272 shares against; and 6,152 shares abstaining.

Item 6. Exhibits

Exhibit Number	Exhibit
4.1	First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, with the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on April 9, 2009, and incorporated herein by reference).
10.1	Consulting Agreement dated June 9, 2009, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 12, 2009, and incorporated herein by reference).
31.1 (a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 (a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 (b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 (b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(a) Filed herewith.

(b) Furnished herewith.

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: August 6, 2009

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

By /s/ Darin G. Holderness
Darin G. Holderness
Vice President, Chief Financial Officer and
Treasurer
(Principal Financial and Accounting Officer)

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit
4.1	First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, with the lenders party thereto and JPMorgan Chase Bank, N.A., as administrative agent (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K on April 9, 2009, and incorporated herein by reference).
10.1	Consulting Agreement dated June 9, 2009, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K on June 12, 2009, and incorporated herein by reference).
31.1 (a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2 (a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1 (b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2 (b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(a) Filed herewith.

(b) Furnished herewith.