CONCHO RESOURCES INC
Form 10-Q
September 10, 2007

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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, 2007

or

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

For the transition period from ____________________ to____________________

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

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

(432) 683-7443

(Registrant s telephone number, including area code)

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

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

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

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 September 7, 2007: 75,750,520 shares.

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PART I FINANCIAL INFORMATION

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PART I Financial Information
ITEM 1. Financial Statements

Concho Resources Inc. and subsidiaries
Consolidated balance sheets
Unaudited

(in thousands, except share and per share data)	June 30, 2007	December 31, 2006
Assets		
Current assets:		
Cash and cash equivalents	$ 10,387	$ 1,122
Accounts receivable:		
Oil and gas	28,976	27,304
Joint operations and other	10,880	22,638
Related parties		1,449
Derivative instruments	81	6,013
Deferred income taxes	82	82
Inventory	1,314	1,309
Prepaid insurance and other	4,857	3,848
Total current assets	56,577	63,765
Property and equipment, at cost:		
Oil and gas properties, successful efforts method:		
Proved properties	1,219,270	1,159,756
Unproved properties	235,365	239,462
Accumulated depletion and depreciation	(123,855)	(84,098)
Total oil and gas properties, net	1,330,780	1,315,120
Other property and equipment, net	6,136	5,535
Total property and equipment, net	1,336,916	1,320,655
Deferred loan costs, net	5,100	4,417
Other assets	335	1,235
Total assets	$ 1,398,928	$ 1,390,072
Liabilities and stockholders equity		
Current liabilities:		
Accounts payable:		
Trade	$ 3,355	$ 16,157
Related parties	1,493	3,593
Other current liabilities:		
Revenue payable	9,497	9,901
Accrued drilling costs	9,251	17,051
Accrued interest	8,833	8,004
Other accrued liabilities	5,673	6,220

Derivative instruments	5,692	6,224
Dividends payable		87
Chase Group unaccredited investors asset purchase obligation		906
Current portion of long-term debt	2,500	400
Current asset retirement obligations	1,545	1,958
Total current liabilities	47,839	70,501
Long-term debt	501,540	495,100
Noncurrent derivative instruments	2,709	
Deferred income taxes	245,863	241,752
Asset retirement obligations and other long-term liabilities	7,072	7,563
Commitments and contingencies (Note K)		
Stockholders equity:		
Series A preferred stock, $0.01 par value; 30,000,000 shares authorized; and zero shares issued and outstanding at June 30, 2007 and December 31, 2006		
Preferred stock, $0.001 par value; 10,000,000 shares authorized; and zero shares issued and outstanding at June 30 ,2007 and December 31, 2006		
Common stock, $0.001 par value; 300,000,000 authorized; 59,167,060 and 59,092,830 shares issued and outstanding at June 30, 2007 and December 31, 2006, respectively.	59	59
Additional paid-in capital	577,993	575,389
Notes receivable from officers and employees	(2,616)	(12,858)
Retained earnings	22,655	12,152
Accumulated other comprehensive income (loss)	(4,186)	414
Total stockholders equity	593,905	575,156
Total liabilities and stockholders equity	$1,398,928	$1,390,072

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

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Concho Resources Inc. and subsidiaries
Consolidated statements of operations
Unaudited

(in thousands, except per share amounts)	Three months ended June 30, 2007	Three months ended June 30, 2006	Six months ended June 30, 2007	Six months ended June 30, 2006
Operating revenues:				
Oil sales	$ 43,096	$34,094	$ 82,467	$ 50,498
Natural gas sales	23,007	17,624	43,982	26,872
Total operating revenues	66,103	51,718	126,449	77,370
Operating costs and expenses:				
Oil and gas production	6,950	5,058	14,209	8,987
Oil and gas production taxes	5,256	4,229	9,943	6,210
Exploration and abandonments	5,864	495	6,305	1,401
Depreciation and depletion	17,609	15,257	37,033	22,496
Accretion of discount on asset retirement obligations	115	88	228	109
Impairments of proved oil and gas properties	2,085	2,978	3,198	3,083
Contract drilling fees stacked rigs	915		4,269	
General and administrative (Including non-cash stock-based compensation of $1,128 and $329 for the three months ended June 30, 2007 and 2006, respectively, and $1,953 and $6,951 for the six months ended June 30, 2007 and 2006, respectively	7,629	3,153	11,921	12,212
Ineffective portion of cash flow hedges	(99)	340	1,156	1,126
Total operating costs and expenses	46,324	31,598	88,262	55,624
Income from operations	19,779	20,120	38,187	21,746
Other income (expense):				
Interest expense	(10,074)	(8,204)	(20,749)	(11,814)
Other, net	208	271	473	574
Total other expense	(9,866)	(7,933)	(20,276)	(11,240)
Income before income taxes	9,913	12,187	17,911	10,506
Income tax expense	(3,988)	(4,566)	(7,363)	(4,313)
Net income	5,925	7,621	10,548	6,193
Preferred stock dividends	(11)	(32)	(45)	(1,178)
Effect of induced conversion of preferred stock				11,601
Net income applicable to common shareholders	$ 5,914	$ 7,589	$ 10,503	$ 16,616
Basic earnings per share:				
Net income per share	$ 0.10	$ 0.14	$ 0.19	$ 0.42

Shares used in basic earnings per share	57,747	54,877	56,369	39,512
Diluted earnings per share:				
Net income per share	$ 0.10	$ 0.13	$ 0.18	$ 0.39
Shares used in diluted earnings per share	59,625	58,344	59,260	42,509

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

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

(in thousands)	Series A Preferred Stock Shares	Series A Preferred Stock Amount	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Notes Receivable from Officers and Employees	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity
BALANCE AT DECEMBER 31, 2005	12,959	$ 130	8,142	$ 8	$ 135,876	$ (9,012)	$ (6,272)	$ (11,060)	$ 109,670
Comprehensive income									
Net income							19,668		19,668
Deferred hedge gains, net of tax of $4,200								7,736	7,736
Net settlement losses included in earnings, net of taxes of $2,030								3,738	3,738
Total comprehensive income									31,142
Issuance of subscribed units	4,518	45	2,259	2	45,329	(3,158)			42,218
Issuance of common stock			578	1	577				578
Conversion of preferred stock	(17,477)	(175)	13,106	13	162				
Issuance of common stock for acquisition			34,795	35	384,301				384,336
Restricted stock issued as stock-based compensation			214		1,044				1,044
Cancellation of restricted stock			(1)						
Stock-based compensation for stock options					7,125				7,125
Stock-based compensation on issuance of units					975				975
Accrued interest officer & employee notes						(688)			(688)
6% Series A Preferred stock dividends							(1,244)		(1,244)
BALANCE AT DECEMBER 31, 2006		$	59,093	$ 59	$ 575,389	$ (12,858)	$ 12,152	$ 414	$ 575,156
Comprehensive income									
Net income							10,548		10,548
Deferred hedge losses, net of tax of ($3,594)								(5,028)	(5,028)
Net settlement losses included in earnings, net of taxes of $306								428	428
Total comprehensive income									5,948
Restricted stock issued as stock-based compensation			20		781				781

Stock-based compensation for stock options			1,173				1,173
Issuance of common stock for acquisition obligation	54		650				650
Proceeds from notes receivable officers & employees				10,482			10,482
Accrued interest officer & employee notes				(240)			(240)
6% Series A Preferred stock dividends					(45)		(45)
BALANCE AT JUNE 30, 2007	$ 59,167	$ 59	$ 577,993	$ (2,616)	$ 22,655	$ (4,186)	$ 593,905

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

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

	Six months ended June 30,	
(in thousands)	**2007**	**2006**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 10,548	$ 6,193
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and depletion	37,033	22,496
Impairments of proved oil and gas properties	3,198	3,083
Accretion of discount on asset retirement obligations	228	109
Exploration expense, including dry holes	5,665	363
Non-cash compensation expense	1,954	6,951
Gas imbalances	54	(2)
Ineffective portion of cash flow hedges	1,156	1,126
Deferred rent liability	41	112
Deferred income taxes	7,399	3,785
Interest accrued on officer and employee notes	(240)	(331)
Amortization of deferred loan costs	1,889	828
Amortization of discount on long-term debt	40	
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	10,640	(8,470)
Prepaid insurance and other	(1,015)	(2,288)
Other assets		12
Accounts payable	(14,902)	6,230
Revenue payable	(404)	(6,087)
Accrued liabilities	(519)	(1,214)
Accrued interest	829	493
Net cash provided by operating activities	63,594	33,389
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on oil and gas properties	(69,889)	(82,460)
Acquisition of oil and gas properties and other assets	(256)	(414,920)
Additions to other property and equipment	(1,114)	(492)
Proceeds from the sale of oil and gas properties	652	
Net cash used in investing activities	(70,607)	(497,872)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from issuance of long-term debt	266,100	485,505
Payments of long-term debt	(257,600)	(88,500)
Proceeds from issuance of subscribed units and common stock		61,178
Payments of preferred stock dividends	(132)	(2,511)
Proceeds from repayment of officer and employee notes	10,482	
Payments for loan origination costs	(2,572)	(5,000)

Negative cash balances				4,629
Net cash provided by financing activities		16,278		455,301
Net increase (decrease) in cash and cash equivalents		9,265		(9,182)
BEGINNING CASH AND CASH EQUIVALENTS		1,122		9,182
ENDING CASH AND CASH EQUIVALENTS	$	10,387	$	
SUPPLEMENTAL CASH FLOWS:				
Cash paid for interest and fees, net of $1,336 and $1,001 capitalized	$	18,891	$	11,294
Cash paid for income taxes	$	1,800	$	100
NON-CASH INVESTING AND FINANCING ACTIVITIES:				
Issuance of common stock in acquisition of oil and gas properties and other assets	$	650	$	384,336
Deferred tax effect of acquired oil and gas properties	$		$	227,735
Issuance of notes receivable issued in connection with capital options	$		$	3,158
Discount on long-term debt	$	(1,000)	$	

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

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

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

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

CEHC s shareholders received 23,767,691 shares of common stock of Resources in exchange for their preferred and common shares of CEHC, excluding eighteen holders owning an aggregate of 254,621 shares of CEHC 6% Series A Preferred Stock and 127,313 shares of CEHC common stock, as discussed in Note G *Stockholders equity and stock issued subject to limited recourse notes*. In addition, the Chase Group transferred their ownership in certain oil and gas properties in Southeast New Mexico to Resources in exchange for cash in the aggregate amount of approximately $409 million and 34,794,638 shares of Resources common stock. As of June 30, 2007 and December 31, 2006, this ownership of the Chase Group represented approximately 59 percent of the total outstanding common stock ownership of the Company.

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

Reverse stock split. On July 3, 2007, the Company s board of directors approved a one-for-two reverse stock split of the Company s outstanding common stock which has been approved by the Company s shareholders and became effective on August 3, 2007 at the completion of the Company s initial public offering. All common shares and per share amounts in the accompanying consolidated financial statements and notes to the consolidated financial statements have been retroactively adjusted for all periods presented to give effect to the reverse stock split.

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

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

Interim financial statements. The accompanying consolidated financial statements of the Company have not been audited by the Company s independent registered public accounting firm, except that the consolidated balance sheet at December 31, 2006 is derived from audited financial statements. In the opinion of management, the accompanying financial statements reflect all adjustments necessary to present fairly the Company s financial position at June 30, 2007, its income for the three and six months ended June 30, 2007 and 2006 and its cash flows for the six months ended June 30, 2007 and 2006. All such adjustments are of a normal recurring nature. In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation. The results for interim periods are not necessarily indicative of annual results.

Certain disclosures have been condensed or omitted from these financial statements. Accordingly, these financial statements should be read with the audited consolidated financial statements and notes thereto included in the

Company s Registration Statement on Form S-1, as amended (Registration No 333-142315).

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

At June 30, 2007, the Company had a gas imbalance liability, included in Asset Retirement Obligations and Other Long-Term Liabilities in the accompanying consolidated balance sheet of approximately $629,000 related to the Company s overtake position of 97,499 Mcf on certain wells and a gas imbalance receivable, included in Other Assets in the accompanying consolidated balance sheet of approximately $335,000 related to the Company s undertake position of 74,466Mcf on certain wells.

General and administrative expense. The Company receives fees for the operation of jointly owned oil and gas properties and records such reimbursements as reductions of General and administrative expense. Such fees totaled approximately $221,000 and $205,000 for the three months ended June 30, 2007 and 2006, respectively, and totaled approximately $630,000 and $421,000 for the six months ended June 30, 2007 and 2006, respectively.

Note C. *Exploratory well costs*

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

The following table provides an aging as of June 30, 2007 and December 31, 2006 of capitalized exploratory well costs based on the date the drilling was completed:

(in thousands)	**June 30, 2007**	**December 31, 2006**
Wells in progress	$ 487	$ 916
Capitalized exploratory well costs that have been capitalized for a period of one year or less	15,948	14,042
Capitalized exploratory well costs that have been capitalized for a period greater than one year	6,071	4,915
Total exploratory well costs	$22,506	$ 19,873

As of June 30, 2007, the Company had one exploratory well in the Western Delaware Basin of Texas on which the drilling was completed for more than one year with a total cost of approximately $6.1 million. This well has been completed in two of the four prospective formations that are being tested in the project area and has found both zones capable of producing gas in the vertical well bores; however, quantities found thus far are not commercial. The current evaluation being conducted on this well is to determine the viability of another one of the four prospective formations which is deeper than the formations to which the well has currently been completed. This formation is a shale formation which is present and productive in another of the Company s exploratory wells located in the Western

Delaware Basin. If determined to be a viable target formation, assessing it would require re-entry into the existing wellbore.

A second well has been drilled in the project area. It was completed and flowing gas to sales during its initial evaluation stage during the six months ended June 30, 2007. This well will be included in the evaluation of the viability of the additional prospective formation in the deeper horizon mentioned above. Accumulated capitalized exploratory costs on this well of approximately $5.2 million are included above in Capitalized exploratory well costs that have been capitalized for a period of one year or less.

The Company anticipates finalizing its evaluation of this deeper, prospective formation in these two wells by the end of the third quarter of 2007. Depending on the results and the evaluation of such activity, the costs capitalized for the completed wells may be charged to expense during the third quarter of 2007.

During the six months ended June 30, 2007, a third well in the Western Delaware Basin was drilled to a shallower, previously untested, prospective formation. During June 2007, the Company determined that the well had not found sufficient reserves to justify its completion or its inclusion in the evaluation of the viability of any additional prospective formations in the project area. The well was temporarily abandoned, and the Company recognized exploratory dry hole expense of approximately $2.8 million. Such expense is included in *Exploration and abandonments* in the accompanying consolidated statement of operations for the three months ended June 30, 2007.

The changes in capitalized exploratory well costs were as follows:

	Six months ended June 30,	
(in thousands)	**2007**	**2006**
Beginning capitalized exploratory well costs	$ 19,873	$ 3,955
Additions to exploratory well costs pending the determination of proved reserves	37,832	17,679
Reclassifications due to determination of proved reserves	(35,199)	(7,756)
Exploratory well costs charged to expense		
Ending capitalized exploratory well costs	$ 22,506	$ 13,878

The Company charged $5,665,000 and $363,000 of exploratory well costs to expense during the six months ended June 30, 2007 and 2006, respectively. These exploratory well costs were capitalized and subsequently expensed in the same annual period; therefore, they are not included in the table above in accordance with FSP No. 19-1.

Note D. *Business combination*

On February 27, 2006, the Company closed a Combination Agreement with the Chase Group whereby ownership in certain oil and gas properties and non-producing leasehold acreage in Southeast New Mexico (the Chase Group Properties) were merged with the properties previously owned by CEHC. The results of the Chase Group Properties have been included in the consolidated financial statements since that date.

The Chase Group received cash in the aggregate amount of $409 million and 34,794,638 shares of Resources common stock valued at $384 million for an aggregate purchase price of $796 million including transaction costs. The value of the Resources common stock shares issued was determined based on an agreed upon fair market value of the assets purchased evaluated using reserve engineering estimates. This entire transaction was accounted for using the purchase method of accounting. At the time of the Combination, due to a difference in book and tax basis of the acquired properties, the Company recognized a deferred tax liability of approximately $227.7 million.

The following table summarizes the final allocated net purchase price of the Combination, including capitalized transaction costs:

(in thousands)	
Proved oil and gas properties	$ 830,540
Unproved oil and gas properties	200,000
Total assets acquired	1,030,540
Asset retirement obligations	(6,158)

Chase investors asset purchase obligation	(906)
Deferred tax liability	(227,735)
Total liabilities assumed	(234,799)
Net purchase price	$ 795,741

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As discussed in Note K Commitments and contingencies, the Company was obligated under the Combination Agreement to offer to purchase additional working interests in the Chase Group Properties from nine individuals within the Chase Group for total consideration of approximately $906,000. In April 2007, the Company satisfied this obligation by paying $256,000 in cash and issuing 54,230 shares of common stock. This aggregate purchase price is reflected in *Proved properties* and the related obligation is reflected in *Chase Group unaccredited investors asset purchase obligation* in the accompanying consolidated balance sheet as of December 31, 2006.

The following table represents pro forma consolidated statements of operations as though the Combination had been completed as of January 1, 2006:

(in thousands, except per share data) (unaudited)	**Pro forma Six months ended June 30, 2006**
Operating revenues	$98,826
Net income applicable to common shareholders	$10,421
Earnings per common share:	
Basic	$ 0.20
Diluted	$ 0.19

On February 27, 2006, the Company signed a contract operator agreement with Mack Energy Corporation (MEC), an affiliate of the Chase Group, whereby the Company engaged MEC as contract operator to provide certain services with respect to the Chase Group Properties. This agreement was replaced with a Transition Services Agreement on April 23, 2007, which terminated upon completion of the Company s initial public offering on August 7, 2007. See further discussion in Note N *Related parties*.

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

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement . This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company will adopt SFAS No. 157 effective January 1, 2008. The Company is currently evaluating the impact of SFAS No. 157.

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

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

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

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

The following table summarizes the Company s asset retirement obligation transactions recorded in accordance with the provisions of SFAS No. 143 during the six months ended June 30, 2007 and 2006:

	Six months ended June 30,	
(in thousands)	**2007**	**2006**
Asset retirement obligations, beginning of period	$ 8,700	$1,120
Liability incurred upon acquiring and drilling wells	131	6,294
Accretion expense	228	109
Liabilities settled upon plugging and abandoning wells		
Revisions to estimated cash flows	(1,393)	(199)
Asset retirement obligations, end of period	$ 7,666	$7,324

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

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

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

Capital calls. The Company s fifth capital call on February 10, 2006, principally funded February 23, 2006, called for 4,155,800 Preferred Units from the Private Investors for $41,558,000 in cash.

For the Company s fifth capital call, also principally funded February 23, 2006, the Officers and certain employees purchased 577,721 shares of CEHC common stock and 351,670 Preferred Units for consideration consisting of $1,200,000 in cash and Purchase Notes in the aggregate principal amount of $3,044,000.

From inception of the Company through February 23, 2006, the Private Investors purchased 16,113,170 Preferred Units for $161.1 million in cash. The Officers had purchased 2,240,083 CEHC common shares and 938,303 Preferred

Units for $3.6 million in cash and Purchase Notes totaling $8.0 million. Certain employees purchased 425,221 Preferred Units for $1.0 million in cash and Purchase Notes totaling $3.8 million.

Series A preferred stock. The Series A preferred stock of the Company consisted of 30 million authorized shares of 6% Series A Preferred Stock with a stated value of $9.00 per share and par value of $0.01 per share. Such shares bore a 6 percent dividend, payable annually in arrears with accrual of such dividend commencing on the date of issue. The Company could have elected to pay the dividend in whole or in part in cash or in additional Units. Upon liquidation, the 6% Series A Preferred Stock would have been ranked senior to all other classes of shares.

Preferred stock dividends were generally paid on the anniversary of date of issue. Preferred stock dividends of approximately $98,000 and $14,000 were paid during the three months ended June 30, 2007 and 2006, respectively. Preferred stock dividends of approximately $132,000 and $2,511,000 were paid during the six months ended June 30, 2007 and 2006, respectively. As discussed in Note A *Organization and nature of operations* and below, the majority of the CEHC preferred stock was converted into Resources common stock on the Combination date. Final dividend payments on converted CEHC 6% Series A Preferred Stock were made in March 2006.

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

Preferred stock. The board of directors is authorized to issue up to 10,000,000 shares of preferred stock with a par value of $0.001 per share (Preferred Stock). The board of directors will determine for each series of issuance:

- the number of shares in any series;
- voting powers, if any;
- redemption provisions, if any;
- dividend rate and other dividend attributes; and
- convertible features or attached rights, if any.

As of June 30, 2007, no shares of Preferred Stock had been issued.

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

At June 30, 2007, the Company had Purchase Notes receivable from certain employees of approximately $2,616,000 comprised of an aggregate principal amounts of $2,361,000 and accrued interest of $255,000.

Valuation of stock issuances treated as Capital Options.

The following table summarizes the Bundled Capital Options activity for the six months ended June 30, 2007:

	Number of Bundled Capital Options	Weighted average exercise price	Grant date fair value
Six months ended June 30, 2007			
Outstanding at beginning of period	938,303	$ 9.52	
Bundled Capital Options granted		$	$
Bundled Capital Options exercised	(938,303)	$ 9.52	
Cancelled / forfeited		$	
Outstanding at end of period		$	

Vested outstanding at end of period	$

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The following table summarizes information about the Company s Vested Bundled Capital Options outstanding and exercisable at June 30, 2007 and December 31, 2006:

Date	Vested Bundled Capital Options Outstanding and Exercisable			
	Number outstanding, vested and exercisable	Weighted average remaining contractual life	Weighted average exercise price	Intrinsic value
June 30, 2007		N / A	N / A	N / A
December 31, 2006	938,303	3.45 years	$9.52	$45,655,000

The following table summarizes the Capital Options activity for the six months ended June 30, 2007:

	Number of Capital Options	Weighted average exercise price	Grant date fair value
Six months ended June 30, 2007			
Outstanding at beginning of period	425,221	$ 9.81	
$10 Capital Options granted		$	$
$15 Capital Options granted		$	$
$10 Capital Options exercised	(172,733)	$ 9.34	
Cancelled / forfeited		$	
Outstanding at end of period	252,488	$ 10.14	
Vested outstanding at end of period	252,488	$ 10.14	

The following table summarizes information about the Company s vested Capital Options outstanding and exercisable at June 30, 2007 and December 31, 2006:

Date	Vested Capital Options Outstanding and Exercisable				
	Exercise prices	Number outstanding, vested and exercisable	Weighted average remaining contractual life	Weighted average exercise price	Intrinsic value
June 30, 2007	$ 10.00	136,480	3.04 years	$ 8.34	$ 677,000
	$ 15.00	116,008	3.34 years	$ 12.26	$

		252,488		$ 10.14	$ 677,000
December 31, 2006	$ 10.00	309,213	3.61 years	$ 8.90	$ 3,268,000
	$ 15.00	116,008	3.83 years	$ 12.26	$ 633,000
		425,221		$ 9.81	$ 3,901,000

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The following table summarizes the stock-based compensation for all Capital Options and is included in *General and administrative expense* in the accompanying consolidated statement of operations for the three and six months ended June 30, 2007 and 2006:

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Stock-based compensation expense from Capital Options:	$	$	$	$975,000
Bundled Capital Options				
Stock-based compensation expense	$	$	$	$508,000
Options vesting during period				242,000
Weighted average grant date fair value per option	$	$	$	$ 2.10
Capital Options Stock-based compensation expense	$	$	$	$467,000
Options vesting during period				119,799
Weighted average grant date fair value per option	$	$	$	$ 3.90

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

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

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

Common stock held in escrow. On February 27, 2006 the Company entered into an agreement with certain stockholders of the Company in which certain of the Company s shareholders placed 430,755 shares of Resources common stock in an escrow account (the Escrow Agreement). The Escrow Agreement provided that if, on or before February 27, 2007 (the Initial Period), the Company consummated one of two specified transactions, the shares held in escrow would be released to the Company for reissuance to Messrs. Leach, Beal, Copeland, Kamradt and Wright. Neither of those specified transactions occurred in the Initial Period. However, the Escrow Agreement specified that if neither of the two specified transactions occurred during the Initial Period, a sale of the Company in a business combination on or before August 26, 2007 where the per share valuation of the Company s common stock in such sale was equal to or greater than $28.00 per share would result in the release of the shares held in escrow to the Company for reissuance to Messrs. Leach, Beal, Copeland, Kamradt and Wright. These shares have been treated as issued and outstanding in the consolidated financial statements at June 30, 2007 and December 31, 2006. This condition did not occur by August 26, 2007. As a result, the escrow agent has been instructed to distribute the escrowed shares to the registered owners thereof that originally deposited the shares.

Note H. ***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.

Restricted stock awards. Under the Plan, the Company has issued 232,216 restricted shares, of which restrictions have lapsed with respect to 60,000 shares. On April 23, 2007, the Company issued a total of 20,000 shares of restricted common stock comprised of 2,500 shares to each of the eight outside directors subject to certain restrictions as set forth in the Plan. These restrictions lapsed

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with respect to 100 percent of the restricted shares on April 23, 2007, the date of grant. The grant date fair value of the stock was estimated to be approximately $340,000 which the Company recognized as stock-based compensation expense in April 2007.

All restricted shares are treated as issued and outstanding in the accompanying consolidated balance sheets. If an employee terminates employment prior the lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company s restricted stock awards during the six months ended June 30, 2007 is presented below:

	Number of common shares	Grant date fair value
Restricted stock:		
Outstanding at December 31, 2006	212,216	
Shares granted	20,000	$340,000
Shares cancelled / forteited		
Lapse of restrictions	(60,000)	$956,000
Outstanding at June 30, 2007	172,216	

The Company recorded stock-based compensation for restricted stock of $560,000 and $88,000, which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations, for the three months ended June 30, 2007 and 2006, respectively, and $781,000 and $88,000 for the six months ended June 30, 2007 and 2006, respectively. Future stock-based compensation expense related to restricted stock outstanding at June 30, 2007 for the remaining six months of 2007 and the years ending December 31, 2008 and 2009 is expected to be approximately $441,000, $882,000, and $454,000, respectively. The income tax benefit recognized in the accompanying statement of operations for restricted stock was approximately $235,000 and $37,000 for the three months ended June 30, 2007 and 2006, respectively, and $327,000 and $37,000 for the six months ended June 30, 2007 and 2006, respectively.

Stock option awards. A summary of the Company s stock option activity under the Plan for the six months ended June 30, 2007 is presented below:

	Six months ended June 30, 2007	
	Number of options [a]	Weighted Average Price
Stock options:		
Outstanding at beginning of period	2,797,997	$8.93
Options granted		$
Options forfeited	(1,275)	$8.00
Options exercised		$
Outstanding at end of period	2,796,722	$8.93

Exercisable at end of period	2,063,499	$ 8.60

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

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The following table summarizes information about the Company s vested stock options exercisable at June 30, 2007 and December 31, 2006:

		Vested Options Exercisable			
Date	Exercise prices	Number vested and exercisable	Weighted average remaining contractual life	Weighted average exercise price	Intrinsic value
June 30, 2007	$ 8.00	1,753,819	7.98 years	$ 8.00	$ 8,243,000
	$ 12.00	309,680	8.58 years	$ 12.00	$ 217,000
		2,063,499		$ 8.60	$ 8,460,000
December 31, 2006	$ 8.00	1,755,094	8.47 years	$ 8.00	$ 15,099,000
	$ 12.00	197,180	8.86 years	$ 12.00	$ 769,000
		1,952,274		$ 8.40	$ 15,868,000

The following table summarizes information about stock-based compensation for options which is recognized in *General and administrative expense* in the accompanying consolidated statement of operations for the three and six months ended June 30, 2007 and 2006:

	Three months ended June 30,		Six months ended June 30,	
	2007	2006	2007	2006
Grant date fair value:				
Time Vesting options [a]	$	$	$	$ 1,931,000
Performance Vesting options:				
Officers [b]				500,000
Certain employee [b]				31,000
Non-officers [c]				142,000
Current officer stock options [d]		3,555,000		3,555,000
Total	$	$ 3,555,000	$	$ 6,159,000

Stock-based compensation expense from stock options:

Time Vesting options [a]	$	$	$	$ 5,085,000
Performance Vesting options:				
Officers [b]	141,000	141,000	279,000	194,000
Certain employee [b]	10,000	10,000	20,000	14,000
Non-officers [c]				505,000
Current officer stock options [d]	418,000	91,000	874,000	91,000
Total	$ 569,000	$ 242,000	$ 1,173,000	$ 5,889,000

(a) Vested immediately as of the date of the Combination, from change of control.

(b) Vesting revised to a three year cliff vesting schedule by approval from CEHC s Board of Directors.

(c) Vested as of the date of the Combination by approval from CEHC s Board of Directors.

(d) June 12, 2006 option grant, by approval of the Company s Board of Directors.

Future stock-based compensation expense related to incentive stock options outstanding at June 30, 2007 for the remaining six months ended December 31, 2007 and the years ending December 31, 2008, 2009 and 2010 is expected to be approximately $789,000, $1,322,000, $443,000, and $99,000 respectively.

Income tax benefit recognized in the income statement for these stock-based compensation arrangements was $239,000 and $94,000 for the three months ended June 30, 2007 and 2006, respectively, and $492,000 and $2,297,000 for the six months ended June 30, 2007 and 2006, respectively. No amounts have been treated as deductions to the Company s current taxable income for the three or six months ended June 30, 2007 and 2006, since no options have been exercised.

Note I. *Derivative financial instruments*

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

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

On February 8, 2007, the Company entered into one natural gas price swap to hedge an additional portion of its estimated natural gas production for the period of March through December 2007. The contract is for 2,100 MMBtu per day at a fixed index price of $7.40 per MMBtu. The index price is based on the Inside FERC El Paso Permian Basin spot price at the first of each month. The Company has designated all of these derivative instruments as cash flow hedges.

The fair market value of these cash flow hedges at June 30, 2007 was a liability of approximately $8.3 million.

The following table sets forth the Company s outstanding natural gas and crude oil zero cost collars and swaps at June 30, 2007:

	Hedged Period	
	2007	**2008**
Natural gas price collars:		
Volume (MMBtu/day)	16,000	13,500
Index price per MMBtu [(a)]	$ 5.98-$9.75[(c)]	$6.50-$9.35
Natural gas price swap:		
Volume (MMBtu/day)	2,100	
Index price per MMBtu [(a)]	$ 7.40	
Crude oil price collars:		
Volume (Bbl/day)	650	
NYMEX price per Bbl [(b)]	$37.95-$41.75	
Crude oil price swaps:		
Volume (Bbl/day)	2,300	2,600
NYMEX price per Bbl [(b)]	$ 67.85	$ 67.50

(a) The index prices for the natural gas price collars are based on the Inside FERC-El

Paso Permian Basis first-of-the-month spot price.

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

(c) Amounts disclosed represent weighted average prices.

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The Company s reported oil and gas revenue and average oil and gas prices includes the effects of oil quality and Btu content, gathering and transportation costs, gas processing and shrinkage, and the net effect of the commodity hedges. The following table summarizes the reclassifications of gains and losses into earnings as a result of periodic contractual cash settlements related to the commodity financial instruments that were previously reported in *Accumulated other comprehensive income (loss):*

	Six months ended June 30,	
(in thousands)	**2007**	**2006**
Cash settlements:		
Gains (losses) reclassified into earnings previously reported in *Accumulated other comprehensive income (loss)*	$(734)	$(4,420)

All of the Company s derivatives are expected to settle within the next two years. Based on futures prices as of December 31, 2006, the Company expects a pre-tax loss of $211,000 to be reclassified into earnings during the year ended December 31, 2007. Based on futures prices as of June 30, 2007, the Company expects a pre-tax loss of $4,976,000 to be reclassified into earnings during the twelve months ended June 30, 2008.

Note J. *Long-term debt*

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

(in thousands)	**June 30, 2007**	**December 31, 2006**
Bank debt:		
1st Lien Credit Facility	$305,000	$455,700
2nd Lien Credit Facility		39,400
New 2nd Lien Credit Facility	197,500	
Unamortized original issue discount on New 2nd Lien Credit Facility	(960)	
Total long-term debt	$501,540	$495,100
Current portion of New 2nd Lien Credit Facility	2,500	400
Total debt	$504,040	$495,500

On February 24, 2006, in conjunction with the Combination, the Company replaced its prior revolving credit facility and its prior term loan facility with a new revolving credit facility, as described below. A portion of the initial advance from the new revolving credit facility was used to repay all funds borrowed under the prior revolving and term credit facilities. Remaining unamortized fees paid in connection with the issuance of the prior revolving and term credit facilities were fully expensed into *Interest expense* in the accompanying consolidated statement of operations for the six months ended June 30, 2006 when the prior revolving and term credit facilities were replaced.

1st Lien Credit Facility. As of February 24, 2006, the Company entered into a credit agreement with a syndicate of banks (the 1st Lien Banks) which provides for a revolving credit facility (the 1st Lien Credit Facility) with commitments from the 1st Lien Banks aggregating $475 million, subject to a borrowing base. The borrowing base is calculated based on the Company s oil and gas reserves. The maturity date of the 1st Lien Credit Facility is February 24, 2010. The Company may also request the issuance of letters of credit up to $20 million. The borrowing commitment is reduced by any outstanding letters of credit. The initial advance on the 1st Lien Credit Facility made on February 27, 2006 was $421 million. The proceeds from this initial advance were used as follows:

Cash payment to the Chase Group in the Combination	$ 400,000,000
Repay balance on prior revolving credit facility	15,900,000
Bank fees and legal costs	5,100,000
	$ 421,000,000

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The initial borrowing base was $475 million. The borrowing base components are redetermined semiannually as of January 1 and June 30 of each year. In addition to the regular redetermination dates listed above, the 1st Lien Credit Facility required a special redetermination as of April 30, 2006. This special redetermination was conducted during the quarter ended June 30, 2006 by the 1st Lien Banks and both the borrowing base and the conforming borrowing base were affirmed at their then current amounts. In addition to the scheduled redeterminations, the Company and the 1st Lien Banks are each provided the option to request an additional redetermination once between the scheduled redeterminations.

Advances on the 1st Lien Credit Facility bear interest, at the Company s option, based on (a) the prime rate of JPMorgan Chase Bank (JPM Prime Rate) (8.25 percent at June 30, 2007) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and JPM Prime Rate advances vary, with interest margins ranging from 100 - 225 basis points and 0 125 basis points, respectively, per annum depending on the available borrowing base utilized. The Company pays commitment fees on the unused portion of the borrowing base ranging from 25 50 basis points per annum depending on the available borrowing base utilized. The amount outstanding under this facility at December 31, 2006 was $455.7 million, of which $432 million was at the Eurodollar rate and $23.7 million was at the JPM Prime Rate. The amount outstanding under this facility at June 30, 2007 was $305 million, all of which was at the Eurodollar rate.

The 1st Lien Credit Facility also includes a same-day advance facility under which the Company may borrow funds on a daily basis from the 1st Lien Banks administrative agent. Advances made on this same-day basis cannot exceed $25 million and the maturity dates cannot exceed fourteen days. The interest rate on this facility is the JPM Prime Rate plus the applicable interest margin. There were no amounts outstanding on this facility at June 30, 2007.

The Company s obligations under the 1st Lien Credit Facility are secured by substantially all of the Company s oil and gas properties. In addition, all but one of the Company s subsidiaries are guarantors, and all subsidiary general partners, limited partners and membership interests owned by the Company and its subsidiaries have been pledged as collateral in the credit agreement. The credit agreement contains various restrictive covenants and compliance requirements which include (a) maintenance of certain financial ratios (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses no greater than 3.5 to 1.0, amended to 4.0 to 1.0 as of March 27, 2007 and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations, to be no less than 1.0 to 1.0, (b) limits on the incurrence of additional indebtedness and certain types of liens and (c) restrictions as to merger and sale or transfer of assets. The Company was in compliance with all covenants of the Credit Facility at June 30, 2007.

On July 6, 2006, the Company entered into the First Amendment to the 1st Lien Credit Facility. The Amendment allowed the Company to obtain additional financing in the form of a $40 million second lien term loan.

2nd Lien Credit Facility. On July 6, 2006, the Company entered into an additional credit agreement for a term loan facility in the amount of $40 million (the 2nd Lien Credit Facility). The full amount of this facility was funded on the closing date to reduce the amount outstanding under the 1st Lien Credit Facility by $32.1 million, with the remaining $7.9 million used for general corporate purposes.

The 2nd Lien Credit Facility provides a $40 million term loan, which bears interest, at the Company s option, based on (a) the prime rate of Bank of America, N.A. (BOA Prime Rate) (8.25 percent at June 30, 2007) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar Rate advances and BOA Prime Rate advances vary, with interest margins of 400 basis points and 250 basis points, respectively. The Company may select interest periods on Eurodollar Rate advances of one, two, three, six, nine and twelve months, subject to availability. Interest is payable at the end of the selected interest period, but no less frequently than quarterly.

The Company is required to repay $100,000 of the 2nd Lien Credit Facility on the last day of each calendar quarter beginning September 30, 2006. The amount outstanding under this facility at December 31, 2006 was $39.8 million. The portion of this facility which is due within the next twelve months, $400,000, is reflected in *Current portion of long-term debt* in the accompanying consolidated balance sheet as of December 31, 2006. On March 27, 2007, the amount outstanding under 2nd Lien Credit Facility was repaid in full.

Refinancing of debt facilities. As of March 27, 2007, the Company amended the 1st Lien Credit Facility, repaid the 2nd Lien Credit Facility and entered into a new 2nd lien credit facility (the New 2nd Lien Credit Facility).

The Company entered into the Second Amendment to the 1st Lien Credit Facility on March 27, 2007. The amendment allowed for the incurrence of additional indebtedness in the form of a $200 million second lien term loan. The amendment also redetermined the borrowing base at $375 million and increased the maximum allowable quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other non-cash income and expenses from 3.5 to 1.0 to 4.0 to 1.0. The amount outstanding under this facility at June 30, 2007 was $305 million, all of which was at the Eurodollar rate.

On March 27, 2007, the Company entered into the New 2nd Lien Credit Facility for a term loan facility in the amount of $200 million. The full amount of the facility was funded on the closing date. The New 2nd Lien Credit Facility was issued at a discount of 0.5 percent; thus, the Company received proceeds of $199.0 million. The proceeds from the borrowing were used to repay the 2nd Lien Credit Facility in full in the amount of $39.8 million without penalty, reduce the amount outstanding under the 1st Lien Credit Facility by $154.0 million, with the remaining $5.2 million used to pay loan fees, accrued interest and for general corporate purposes.

The New 2nd Lien Credit Facility provides a $200 million term loan, which bears interest, at the Company s option, based on (a) the BOA Prime Rate (8.25 percent at June 30, 2007) or (b) a Eurodollar rate (substantially equal to the London Interbank Offered Rate). The interest rates of Eurodollar rate advances and prime rate advances vary, with interest margins of 375 basis points and 225 basis points, respectively, until the sooner to occur of an initial public offering by the Company or the first anniversary of the closing date of the loan; thereafter, interest margins on Eurodollar rate advances and prime rate advances will be 425 basis points and 275 basis points, respectively. The Company may select interest periods on Eurodollar rate advances of one, two, three, six, nine and twelve months, subject to availability. Interest is payable at the end of the selected interest period, but no less frequently than quarterly.

The Company is required to repay $0.5 million of the New 2nd Lien Credit Facility on the last day of each calendar quarter beginning June 30, 2007. There are five quarters, or $2,500,000, classified as *Current portion of long-term debt* on the consolidated balance sheet as of June 30, 2007, because the end of the second quarter fell on a Saturday. The next business day convention contained in the credit agreement allowed for the payment to be due on Monday, July 2nd. The maturity date of the term loan facility is March 27, 2012. The Company has the right to prepay the outstanding balance under the term loan facility at any time. The Company will not incur a prepayment penalty on any principal amount prepaid during the first twelve months of the loan. A two percent prepayment penalty will be incurred on any principal amount prepaid during the second year following the closing and one percent penalty will be incurred during the third year. After the third year, no prepayment penalty will be incurred.

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

The amount outstanding under New 2nd Lien Credit Facility at June 30, 2007 was $199.1 million, net of a discount of $0.9 million, all of which was at the Eurodollar rate. The Company was in compliance with all covenants of the New 2nd Lien Credit Facility at June 30, 2007.

The Company paid an arrangement fee of $2.5 million at the date of closing. This fee will be amortized to *Interest expense* over the five-year term of the facility beginning in April 2007.

The amendment of the 1st Lien Credit Facility on March 27, 2007, resulted in a $100 million, or 21 percent, reduction of the borrowing base. As such, the pro rata portion of the remaining debt issuance costs associated with the 1st Lien Credit Facility, totaling approximately $766,000, was written off and included in *Interest expense* in the first quarter of 2007. The remaining debt issuance costs of $433,000 associated with the 2nd Lien Credit Facility repaid in full on March 27, 2007, were written off and included in *Interest expense* in the first quarter of 2007.

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Principal maturities of long-term debt outstanding at June 30, 2007 for the six months ended December 31, 2007 and the years ended December 31, 2008, 2009, 2010 and 2011 and thereafter, are as follows:

(in thousands)

2007	$ 1,500
2008	2,000
2009	2,000
2010	307,000
2011	2,000
2012 and thereafter	190,500
Total	$ 505,000

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

Daywork drilling contract commitments. The Company signed a daywork drilling contract with a drilling contractor (Contractor B) on July 20, 2006, that provided the Company exclusive use of one rig with an operating day rate of $15,500 for a term that commenced on August 1, 2006 and ended on June 15, 2007. During February 2007, management decided to stack this rig due to budget modifications. The Company incurred costs of approximately $915,000 and $1,296,000 during the three and six months ended June 30, 2007, respectively. These costs were minimized as Contractor B secured work for the rig and refunded the Company the difference between the current operating day rate pursuant to the contract and the operating day rate received from the new customer.

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

The Company signed daywork drilling contracts with Silver Oak Drilling, LLC (Silver Oak), an affiliate of the Chase Group, on August 1, 2006, that provides the Company use of four drilling rigs for a term that commenced on August 1, 2006 and ends on July 31, 2007. The Company may direct the rig to locations located in New Mexico as needed. If the Company moves the rig out of certain New Mexico counties specified in the contract, all effective daywork rates will be increased by an additional $2,000 per day. The Company is solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, with the exception that Silver Oak is liable for its employees, subcontractors and invitees. In addition, Silver Oak is responsible for pollution or contamination from their equipment. Silver Oak will release the Company of any liability for negligence of any party connected to Silver Oak. The operating day rate is $14,500 for two of the contracts and $13,500 for the other two contracts. The operating day rate can be revised to reflect changes in costs incurred by more than 5 percent by Silver Oak for labor, insurance premiums, fuel, and/or an increase in the number of Silver Oak s personnel needed. Under the contract, the Company must pay the full operating day rate for each day during the contract term. Although there is no early termination provision in the contract, Silver Oak has a duty to mitigate damages to the Company by reasonably attempting to secure replacement contracts for the rigs if they are released by the Company or if any contract is terminated by Silver Oak prior to the expiration of the term of the contract. The Company will then be entitled to a 75 percent credit for any revenues received by Silver Oak. Even if the Company releases the rigs, the Company, with 20 days notice, may withdraw its release and reactivate the contract for the remainder of the term to the extent the rig has not been committed to a third party in mitigation of the Company s damages. During February 2007, management decided to stack these four rigs due to budget modifications. The Company incurred no costs in the three months ended June 30, 2007 and approximately $2,973,000 during the six months ended June 30, 2007, based on the drilling agreement described above. As of April 1, 2007, the Company began to utilize all four rigs, in order to proceed with its 2007 drilling budget.

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

Oil & gas lease extension payment. The Company is party to an agreement which, in part, governs the exploration activities on the Company s acreage in the Western Delaware Basin shale play in Culberson County, Texas. The agreement contains a three-well drilling commitment. In addition to the drilling well requirement, the agreement required the Company to pay an additional $2.1 million ($150 per net acre for 13,952 net acres) in order to maintain its leasehold position, with such payment required within 90 days after the completion of the drilling of the third of the Company s three-well drilling commitment.

As of January 1, 2007, the Company had drilled or was drilling all three of these wells. The last of the three wells drilled reached total depth on January 19, 2007. On April 17, 2007, the Company made the payment of $2.1 million described above.

Chase Group accredited and unaccredited investors asset purchase obligation. As discussed in Note D *Business combination*, on February 27, 2006, as required by the Combination Agreement, the Company agreed to purchase working interests in the Chase Group Properties from certain individuals within the Chase Group. On May 18, 2006, the Company purchased interests in the Chase Group Properties from ten individuals within the Chase Group who were accredited investors in exchange for $8.9 million in cash and 111,323 shares of Resources common stock valued at $1.4 million for an aggregate purchase price of $10.3 million. The value of the common shares issued was $12 per share, as required by the Combination Agreement. The aggregate purchase price is reflected in *Proved properties* in the accompanying consolidated balance sheet at December 31, 2006. This transaction is included in the aggregate purchase price disclosed in Note D *Business combination*.

The Company was further obligated to offer to purchase additional interests in the Chase Group Properties from nine individuals within the Chase Group. In April 2007, the Company satisfied this obligation by paying $256,000 in cash and issuing 54,230 shares of common stock. The aggregate purchase price is reflected in *Proved properties* and the related obligation is reflected in *Chase Group unaccredited investors asset purchase obligation* in the accompanying consolidated balance sheet at December 31, 2006. This transaction is included in the aggregate purchase price disclosed in Note D *Business combination*.

Note L. *Regulatory matters*

From 1984 through 1997, the owners of the Grayburg-Jackson West Cooperative Unit (GJ Unit), a group of formations and intervals unitized by state regulatory authorities, comprised of approximately 2,400 acres in Eddy County, New Mexico and which comprises a portion of the Chase Group Properties, drilled or deepened approximately 70 wells that produced from zones below a depth approved as the unitized formation. The owners of the working interests in the GJ Unit possessed the ownership rights entitling them to produce hydrocarbons from the subject producing intervals below the unitized formation, but had not obtained the necessary regulatory approval (1) as to certain wells, to drill or deepen below the base of the unitized formation or (2) to produce hydrocarbons from intervals below the base of the unitized formation and to commingle such production with production from the unitized formation. In connection with the failure to obtain the required regulatory approval to produce on a commingled basis from these deeper intervals, the operators filed incorrect perforation and completion reports with state regulatory authorities, and filed monthly production reports that did not disclose that hydrocarbons had been produced from intervals below the unitized formation and that hydrocarbons produced from these deeper intervals were improperly commingled with production from the unitized formation (although the reports apparently reflected the actual volumes produced by the wells). As a result, a unit royalty interest owner in the unitized formation was overpaid and the State of New Mexico, which was the owner of the royalty interest in the subject producing intervals below the unitized formation, was underpaid for several years.

On November 15, 2005, MEC filed an application with the New Mexico Oil Conservation Division (NMOCD) to expand the vertical limit of the unitized formation to include the deeper intervals that had been accessed, produced and commingled without obtaining regulatory approval. A hearing on the application was originally scheduled for December 15, 2005, but was continued at the request of MEC. On February 27, 2006, the combination transaction occurred and, as a result, the Company acquired the GJ Unit.

On April 13, 2006, the NMOCD held a hearing on MEC s application to expand the vertical limit of the unitized formation. Representatives of MEC, acting under the Contract Operator Agreement with MEC, participated in the hearing and presented testimony during that hearing that intervals below the unitized formation had not been tested or developed. Based on the application submitted by MEC and the evidence and testimony presented at the hearing, on June 13, 2006, the NMOCD approved the application and entered its order expanding the vertical limit of the unitized formation to include certain deeper intervals, including one of those that had previously been produced and commingled without regulatory approval.

Over the course of developing our drilling program for the Chase Group Properties in July and August 2006, the Company discovered the existence of these violations and this testimony. Following further investigation by the Company s employees and discussions with a representative of Chase Oil and MEC and the Company s counsel, the Company reported these developments to the Company s board of directors. Because this matter related to ongoing regulatory violations by entities that were under the control of certain members of the Company s board of directors, the Company s board of directors determined on September 6, 2006, to form a special committee of the board of directors that consisted of independent and disinterested non-management directors for the purpose of investigating the matters identified by the Company s management relating to the GJ Unit. The special committee engaged separate legal counsel to assist it with its investigation of this matter. Also, in September 2006, representatives of MEC and the Company met with relevant regulatory authorities from the State of New Mexico, and voluntarily self-reported the matters related to the GJ Unit, and the Company filed amended reports to correct prior reporting inaccuracies.

As a result of these actions, the Company, along with MEC, entered into a settlement agreement with the New Mexico State Land Office on November 2, 2006 related to the underpayment of royalties arising from these circumstances. Under the terms of the settlement agreement, MEC paid $615,444 to the State of New Mexico for underpayment of royalties and interest thereon. The Company was not required to make any payments under the settlement agreement. Further, on January 22, 2007, the State of New Mexico advised the Company that there was no basis for a compliance and enforcement proceeding against the Company and no evidence of a knowing and willful violation of applicable law by the Company. On January 19, 2007, MEC entered into an Agreed Compliance Order and agreed to pay a penalty of $250,000 for its violations of applicable rules, regulations and statutes. Finally, the NMOCD approved the Company s correction of the prior records related to the GJ Unit and, in February 2007, approved the Company s application to expand the vertical limit of the unitized formation below the depth of the intervals that had previously been improperly produced and commingled with production from the unitized formation and to bring all of the wells in the GJ Unit into compliance with all applicable rules, regulations and statutes.

The special committee of the board of directors examined relevant documents provided by the Company and its regulatory counsel in New Mexico, conducted interviews of members of management and heard a presentation from a representative of Chase Oil and MEC. The special committee also monitored the activities of the Company and the Company s legal counsel during the discussions and proceedings with relevant New Mexico regulatory authorities. Based on its review of this matter, the special committee recommended the adoption of certain policies and procedures governing the operation of all legal proceedings involving the Company as well as a review of the due diligence processes associated with future acquisitions of properties. The special committee also recommended certain actions to address corporate governance matters at the Company. Finally, the special committee reviewed the conduct of the Company s officers and directors to determine whether any such conduct would indicate that an officer or director was unsuitable to continue in their position, and the special committee did not determine that any officer or director was unsuitable to continue in their position with the Company.

Note M. *Income taxes*

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

The Company adopted the provisions of FASB Interpretation No. 48 Accounting for Uncertainty in Income Taxes (FIN 48) an interpretation of FASB Statement No. 109 Accounting for Income Taxes , on January 1, 2007. At the time of adoption and as of June 30, 2007, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2004 2006 remain subject to examination by major tax jurisdictions.

The Company s provision for income taxes differed from the U.S. statutory rate of 35% primarily due to state income taxes and non-deductible expenses. The effective income tax rate for the six months ended June 30, 2007 was 41.1%.

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Note N. ***Related parties***

Contract operator agreement. On February 27, 2006, the Company signed a contract operator agreement with MEC, an affiliate of the Chase Group, whereby the Company engaged MEC as contract operator to provide certain services with respect to the Chase Group Properties. The initial term of the contract operator agreement was 5 years commencing on March 1, 2006 and ending on February 28, 2011. The Company and MEC entered into a Transition Services Agreement on April 23, 2007, which terminated the contract operator agreement and under which MEC will provide certain field level operating services on the Chase Group Properties.

The Company incurred charges from MEC of approximately $5.1 million and $10.2 million for the three and six months ended June 30, 2007, respectively, for services rendered under the contract operator agreement.

The Company incurred charges from MEC of approximately $1.3 million for both the three and six months ended June 30, 2006 for services rendered under the contract operator agreement.

At June 30, 2007, the Company had outstanding invoices payable to MEC of approximately $0.2 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

At December 31, 2006, the Company had outstanding invoices payable to MEC of approximately $1.8 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

Transition Services Agreement. The Company entered into a Transition Services Agreement with MEC whereby it provides services to the properties in Southeast New Mexico that the Company acquired from Chase Oil and its affiliates in the Combination. The Transition Services Agreement replaced the prior Contract Operator Agreement with MEC that the Company entered into in connection with the initial closing of the Combination. The Company agreed with MEC to terminate the Contract Operator Agreement in connection with the execution of the Transition Services Agreement on April 23, 2007. Under the Transition Services Agreement, MEC provides field level services, including pumping, well service oversight and supervision and certain equipment for workover and recompletion services, at costs prevailing in the area of the subject properties, but not to exceed charges for comparable services by and among MEC and its affiliates. MEC performed substantially similar services on behalf of the Company under the Contract Operator Agreement prior to its termination. The Transition Services Agreement terminates upon the earlier to occur of (i) February 28, 2011; (ii) the date on which the Company completes the initial sale of its shares of common stock to the public pursuant to a registration statement filed under the Securities Act of 1933, as amended; or (iii) a change of control, as defined, or sooner as otherwise provided in the agreement or mutually agreed upon by the parties. The Transition Services Agreement was terminated effective August 7, 2007 pursuant to the Company s completion of its initial public offering. See Note P *Subsequent events*. Accordingly, upon termination, the Company s employees along with third party contractors have assumed the operation of the subject properties.

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

The Company incurred charges from these related party vendors of approximately $10.7 million and $22.1 million for the three and six months ended June 30, 2007, respectively, for services rendered.

The Company incurred charges from these related party vendors of approximately $11.4 million and $13.4 million for the three and six months ended June 30, 2006, respectively, for services rendered.

At June 30, 2007, the Company had outstanding invoices payable to the other related party vendors identified above of approximately $1.3 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheets.

At December 31, 2006, the Company had outstanding invoices payable to the other related party vendors mentioned above of approximately $1.8 million which are reflected in *Accounts payable related parties* in the accompanying consolidated balance sheet.

Overriding royalty and royalty interests. Certain members of the Chase Group own overriding royalty interests in certain of the Chase Group Properties. The amount paid attributable to such interests was approximately $458,000 and $973,000 for the three and six months ended June 30, 2007, respectively. The amount paid attributable to such interests was approximately $501,000 and $973,000 for the three and six months ended June 30, 2006.

Royalties are paid on certain properties located in Andrews County, Texas to a partnership of which one of the Company s directors is the General Partner, and who also owns a 3.5% partnership interest. The Company paid approximately $36,000 and $59,000 for the three and six months ended June 30, 2007, respectively, and approximately $1,000 for each of the three and six months ended June 30, 2006. The Company also paid this entity a $24,000 lease bonus during the six months ended June 30, 2007. The Company had no outstanding invoices payable to this entity as of June 30, 2007 or December 31, 2006.

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 is now owned equally by such officer and a non-officer employee of the Company. The amount attributable to such interest was approximately $2,000 during the three and six months ended June 30, 2007. During the three and six months ended June 30, 2007 and 2006, no payments were made related to this overriding royalty interest.

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

The Company paid Caza approximately $1.8 million for the three and six months ended June 30, 2006 for these interests. Approximately all of the costs were capital prospect costs which are reflected in *Unproved properties* in the accompanying consolidated balance sheet at December 31, 2006.

The Company paid Caza approximately $3,000 for the six months ended June 30, 2007 for delay rentals which are reflected in *Unproved properties* in the accompanying consolidated balance sheet at June 30, 2007. There were no amounts paid to Caza during the three months ended June 30, 2007 for these interests.

At June 30, 2007 and December 31, 2006, the Company had no outstanding invoices owed to Caza.

Note O. *Net income per share*

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

The computation of diluted income per share reflects the potential dilution that could occur if securities or other contracts to issue common stock that are dilutive to income were exercised or converted into common stock or resulted in the issuance of common stock that would then share in the earnings of the Company. These amounts include unexercised Bundled Capital Options, Capital Options, stock options (as issued under the Stock Option Plan of CEHC adopted in 2004 and the Plan of CRI adopted in 2006, both as described in Note H *Stock incentive plan*) and restricted stock. Potentially dilutive effects are calculated using the treasury stock method.

The CEHC 6% Series A Preferred Stock were entitled to receive an amount equal to its stated value ($9.00) plus any unpaid dividends upon occurrence of a liquidation event, as defined. In connection with the Combination on February 24, 2006, a liquidation event occurred. Instead of receiving the stated value, the holders of the CEHC 6% Series A Preferred Stock agreed to accept 0.75 shares of Resources common stock in exchange for each share of CEHC 6% Series A Preferred Stock. This was considered to be an induced conversion, as defined in the FASB Emerging Issues Task Force Topic D-42, The Effect on the Calculation of Earnings per Share for the Redemption or Induced Conversion of Preferred Stock. The excess of the carrying amount of the CEHC 6% Series A Preferred Stock over the fair value of the Resources common stock issued is required to be added to 2006 net income to arrive at 2006 net income applicable to common shareholders for the six months ended June 30, 2006.

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The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the three and six months ended June 30, 2007 and 2006:

	Three months ending June 30,		Six months ending June 30,	
(in thousands)	**2007**	**2006**	**2007**	**2006**
Weighted average common shares outstanding:				
Basic	57,747	54,877	56,369	39,512
Dilutive Bundled Capital Options	660	2,583	1,695	2,332
Dilutive Capital Options	160	187	204	150
Dilutive common stock options	996	696	921	515
Dilutive restrictive stock	62	1	71	
Diluted	59,625	58,344	59,260	42,509

For the three and six months ended June 30, 2007 and 2006, the effects of all securities (including Bundled Capital Options, Capital Options and stock options) were included in the computation of diluted earnings per share because the Company had net income applicable to common shareholders and, therefore, there were no antidilutive effects.

For the six months ended June 30, 2006, the effect of 450,000 common stock options were excluded from the computation of diluted earnings per share because the effect would have been antidilutive.

Note P. ***Subsequent events***

Initial public offering. On August 7, 2007 the Company completed an initial public offering (the IPO) of its common stock. The Company sold 13,332,851 shares and certain shareholders, including our executive officers and members of the Chase Group, sold 7,554,256 shares of Resources common stock, in each case, at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.4 million, the Company received net proceeds of approximately $139.3 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,133,066 additional shares of Resources common stock. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.1 million, the Company received net proceeds of approximately $33.9 million. The aggregate net proceeds of approximately $173.2 million received by the Company at closing on August 7, 2007 and August 9, 2007 were utilized as follows:

Partial prepayment of 1st Lien Credit Facility August 20, 2007	$ 86,575,000
Partial repayment of New 2nd Lien Credit Facility August 9, 2007	$ 86,575,000

Repayment of portion of New 2nd Lien Credit Facility. As mentioned above, IPO proceeds in the amount of $86.6 million were used to repay a portion of the New 2nd Lien Credit Facility on August 9, 2007. Subsequent to such repayment the outstanding balance, net of remaining original issue discount, as of August 9, 2007, was $112.9 million. As set forth by this facility s credit agreement and as described in Note J *Long-term debt,* effective on the consummation of the IPO, the interest margins on Eurodollar rate advances and prime rate advances increased to 425 basis points and 275 basis points, respectively.

A pro rata portion of the deferred loan costs associated with the New 2nd Lien Credit Facility were written off to interest expense in August 2007 in the amount of approximately $1.0 million. Additionally, a pro rata portion of the unamortized original issue discount related to the New 2nd Lien Credit Facility was written off to interest expense in August 2007 in the amount of approximately $0.4 million.

Stock option awards. In August 2007, the Company s board of directors approved the issuance of 215,000 stock options under the Plan. These options have an exercise price of $12.85, a contractual term of 10 years from the date of grant, and vest using a four year graded vesting schedule. For more details of the Plan, see Note H *Stock incentive plan.*

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

In September 2007, the Compensation Committee of the Company s board of directors approved the grant of 112,543 shares of restricted common stock to the non-officer employees of the Company, subject to certain restrictions as set forth in the Plan and respective restricted stock agreements between the Company and each such employee. These restrictions lapse with respect to 100 percent of the restricted shares three years from the date of grant. The grant date fair value of the stock was estimated by the Company to be approximately $1,620,000 which the Company will recognize as stock-based compensation expense over the next three years beginning September 2007. For more details of the Plan, see Note H *Stock incentive plan.*

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Note Q. ***Supplementary information***

Costs incurred for oil and gas producing activities

(in thousands)	**Three months ended June 30, 2007**	**Three months ended June 30, 2006**	**Six months ended June 30, 2007**	**Six months ended June 30, 2006**
Property acquisition costs:				
Proved	$ 8,000	$15,826	$ 8,000	$ 823,950
Unproved	(4,886)	5,564	(4,096)	215,365
Exploration	30,027	8,615	41,734	14,646
Development	2,072	41,812	17,373	50,587
Capitalized asset retirement obligations	(922)	212	(1,289)	6,403
Total costs incurred for oil and gas properties	$34,291	$72,029	$61,722	$1,110,951

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

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with management s discussion and analysis contained in our Prospectus dated August 2, 2007 and filed with the Securities and Exchange Commission (SEC) pursuant to Rule 424 (b) on August 3, 2007, as well as with the consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q.

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

Overview

We are an independent oil and natural gas company engaged in the acquisition, development, exploitation and exploration of oil and natural gas properties. Our conventional operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. These conventional operations are complemented by our activities in unconventional emerging resource plays. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

Our operations are primarily concentrated in the Permian Basin, the largest onshore oil and gas basin in the United States. As of December 31, 2006, 99% of our total estimated net proved reserves were located in the Permian Basin and consisted of approximately 57% crude oil and 43% natural gas. This basin is characterized by an extensive production history, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. The primary producing formation in the Permian Basin under our core properties in Southeast New Mexico is the Yeso formation, including the Paddock interval, which is located at depths ranging from 3,800 feet to 5,800 feet, and the Blinebry interval, the top of which is located approximately 400 feet below the base of the Paddock interval. We have assembled a multi-year inventory of development drilling and exploitation projects, including further projects targeting the Yeso formation, that we believe will allow us to grow proved reserves and production. We have also acquired significant acreage positions in unconventional emerging resource plays, where we intend to apply horizontal drilling, advanced fracture stimulation and enhanced recovery technologies.

Factors that significantly affect our results

Our revenue, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural gas prices have historically been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and gas that we can economically produce and our ability to access capital.

We generally hedge a portion of our expected future oil and natural gas production to reduce our exposure to fluctuations in commodity price. See Liquidity and capital resources Hedging for a discussion of our hedging and hedge positions.

Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well decreases. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil or natural gas it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce and by implementing secondary recovery techniques. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on costs necessary to produce our reserves as well as the costs necessary to add reserves through drilling and acquisitions. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost-effective manner and to timely obtain drilling permits and regulatory approvals.

Items impacting comparability of our financial results

Our historical results of operations for the periods presented may not be comparable, either from period to period or going forward, for the reasons described below.

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Combination transaction

We were formed in February 2006 as a result of the combination transaction between Concho Equity Holdings Corp. and Chase Oil Corporation, Caza Energy LLC (Caza) and certain other parties thereto (collectively with Chase Oil Corporation and Caza, the Chase Group).

Concho Equity Holdings Corp. is our predecessor for accounting purposes. As a result, our historical financial statements prior to February 27, 2006, are the financial statements of Concho Equity Holdings Corp. Concho Equity Holdings Corp. was formed on April 21, 2004, and did not own any material assets and did not conduct substantial operations other than organizational activities until it acquired oil and gas properties from Lowe Partners, LP on December 7, 2004 (the Lowe Acquisition). For a discussion of the results of operations of Concho Resources Inc. (Resources) (as the accounting successor to Concho Equity Holdings Corp.), please read Results of operations of Concho Resources Inc.

As of December 31, 2006, approximately 76% of our PV-10 was attributable to the properties contributed to us by the Chase Group in the combination transaction.

Additional indebtedness and other expenses

During 2006 and 2007, we incurred additional indebtedness and other expenses as a result of our rapid growth, particularly as a result of the combination transaction. Our historical financial information prior to February 28, 2006 does not give effect to the results of operation of the properties contributed by the Chase Group in the combination transaction, as well as, the following items:

- we closed the combination transaction on February 27, 2006 and properties were contributed to us by the Chase Group that represent approximately 76% of our PV-10 as of December 31, 2006;

- we incurred approximately $405 million of new indebtedness upon the initial closing of the combination transaction;

- we entered into a $200.0 million second lien term loan facility on March 27, 2007, from which we received proceeds of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes; and

- we have incurred additional general and administrative costs as a result of the expansion of our technical and administrative staffs and as a result of increased amounts of professional fees.

Curtailment of drilling

We determined in January 2007 to reduce our drilling activities for the first three months of 2007. This determination was due to a decline in oil and natural gas prices in January 2007 compared to such prices in the fourth quarter of 2006, the costs of goods and services necessary to complete our drilling activities and the resulting effect of these circumstances on our expected cash flow for the three months ended March 31, 2007. In addition, we determined to reduce our drilling activities and curtail capital expenditures until we were able to complete our second lien term loan facility in March 2007 in order to preserve liquidity. Also due to the reduced drilling activities described above, we recorded an expense in the six months ended June 30, 2007 of approximately $4.3 million for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. Approximately $3.0 million of this amount was paid to Silver Oak Drilling, LLC, which is an affiliate of the Chase Group. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007, and we believe we will spend our revised 2007 exploration and development budget of approximately $183.0 million during 2007. See Recent events for a discussion of the revised 2007 budget.

Recent events

On June 27, 2007, we were notified that a natural gas processing plant through which we process and sell a portion of the production from our Shelf Properties in New Mexico was shut-down for repairs as a result of a storm. Approximately 40 MMcfe per day of our production was shut-in as a result of this plant shut-down. The plant became fully operational on July 3, 2007, and we resumed production from all of our properties that had been affected. On

July 16, 2007 this plant was shut-down again for repairs. Approximately 40 MMcfe per day of our production was shut-in as a result of this plant shut-down. The plant became fully operational on July 20, 2007, and we resumed production from all of our properties that had been affected.

On August 7, 2007 we completed an initial public offering (the IPO) of our common stock. We sold 13,332,851 shares and certain shareholders, including our executive officers and members of the Chase Group, sold 7,554,256 shares of Resources common stock, in each case, at $11.50 per share. After deducting underwriting discounts of approximately $9.6 million and offering expenses of approximately $4.4 million, we received net proceeds of approximately $139.3 million. In conjunction with the IPO, the underwriters were granted an option to purchase 3,133,066 additional shares of Resources common stock from us. The underwriters fully exercised this option and purchased the additional shares on August 9, 2007. After deducting underwriting discounts of approximately $2.1 million, we received net proceeds of approximately $33.9 million. The aggregate net proceeds of approximately $173.2 million received by us at closing on August 7, 2007 and August 9, 2007 were utilized to repay a portion of the 2nd Lien Credit facility in the amount of $86.6 million on August 9, 2007,and to prepay a portion of the 1st Lien Credit Facility in the amount of $86.6 million on August 20, 2007. A pro rata portion of the deferred loan costs associated with the 2nd Lien Credit facility were written off to interest expense in August 2007 in the amount of approximately $1.0 million. Additionally, a pro rata portion of the unamortized original issue discount related to the 2nd Lien Credit facility was written off to interest expense in August 2007 in the amount of approximately $0.4 million.

On August 16, 2007, our board of directors approved an increase in its 2007 exploration and development budget in the amount of $29 million from $154 million to $183 million. Our 2007 capital budget is comprised of the following:

(in millions)	Original Budget	Revised Budget
Drilling and recompletion opportunities in our core operating area	$119.4	$135.2
Projects in our emerging plays	15.7	28.9
Projects operated by third parties	14.2	14.2
Acquisition of leasehold acreage and other property interests	4.7	4.7
	$154.0	$183.0

We anticipate that this incremental $29 million in its 2007 exploration and development budget will be funded by utilizing availability under our revolving credit facility.

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Results of operations of Concho Resources Inc.

The following table presents selected financial and operating information of Concho Resources Inc. (as successor to Concho Equity Holdings Corp.) for the three and six months ended June 30, 2007 and 2006:

	Three months ended June 30,		Six months ended June 30,	
	2007	**2006**	**2007**	**2006**
(in thousands, except price data)	**(unaudited)**		**(unaudited)**	
Oil sales	$43,096	$34,094	$ 82,467	$50,498
Natural gas sales	23,007	17,624	43,982	26,872
Total operating revenues	66,103	51,718	126,449	77,370
Operating costs and expenses	46,324	31,598	88,262	55,624
Interest, net and other revenue	9,866	7,933	20,276	11,240
Income before income taxes	9,913	12,187	17,911	10,506
Income tax expense	(3,988)	(4,566)	(7,363)	(4,313)
Net income	$ 5,925	$ 7,621	$ 10,548	$ 6,193
Production volumes:				
Oil (MBbl)	730	580	1,438	893
Natural gas (MMcf)	2,953	2,502	5,905	3,916
Natural gas equivalent (MMcfe)	7,330	5,985	14,536	9,273
Average prices:				
Oil, without hedges ($/Bbl)	$ 60.15	$ 64.04	$ 57.16	$ 61.48
Oil, with hedges ($/Bbl)	$ 59.07	$ 58.73	$ 57.33	$ 56.56
Natural gas, without hedges ($/Mcf)	$ 7.77	$ 6.93	$ 7.42	$ 6.87
Natural gas, with hedges ($/Mcf)	$ 7.79	$ 7.04	$ 7.45	$ 6.86
Natural gas equivalent, without hedges ($/Mcfe)	$ 9.12	$ 9.11	$ 8.67	$ 8.82
Natural gas equivalent, with hedges ($/Mcfe)	$ 9.02	$ 8.64	$ 8.70	$ 8.34

Bbl Barrel

MBbl Thousand Barrels

Mcf Thousand cubic feet

MMcf Million cubic feet

Mcfe Thousand cubic feet of natural gas equivalent

(computed on an energy equivalent basis of one Bbl equals six Mcf)

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

Three months ended June 30, 2007, compared to three months ended June 30, 2006

Oil and gas revenues. Revenue from oil and gas operations for the three months ended June 30, 2007 were $66,103,000, a $14,385,000 (28%) increase from $51,718,000 for the three months ended June 30, 2006. This increase was primarily due to successful drilling efforts during 2006 and 2007. Total production for the three months ended June 30, 2007 was 7,330 MMcfe, a 1,345 MMcfe (22%) increase from 5,985 MMcfe for the three months ended June 30, 2006. Total production during the three months ended June 30, 2007 was reduced by approximately 160 MMcfe as a result of the temporary shut-down of a natural gas processing plant through which we process and sell a portion of our production. See Items impacting comparability of our financial results Recent events. In addition, average realized oil prices (after giving effect to hedging activities) were $59.07 per Bbl during the three months ended June 30, 2007, an increase of 1% from $58.73 per Bbl during the three months ended June 30, 2006; average realized natural gas prices (after giving effect to hedging activities) were $7.79 per Mcf during the three months ended June 30, 2007, an increase of 11% from $7.04 per Mcf during the three months ended June 30, 2006; and average realized natural gas equivalent prices (after giving effect to hedging activities) were $9.02 per Mcfe during the three months ended June 30, 2007, an increase of 4% from $8.64 per Mcfe during the three months ended June 30, 2006.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. During the three months ended June 30, 2007, our commodity price hedges decreased oil revenues by $783,000 ($1.07 per Bbl) and increased gas revenues by $49,000 ($0.02 per Mcf). During the three months ended June 30, 2006, our commodity price hedges decreased oil revenues by $3,079,000 ($5.30 per Bbl) and increased gas revenues by $282,000 ($0.11 per Mcf).

The effect of the commodity price hedges in decreasing oil revenues during the three months ended June 30, 2007 less than their effect of decreasing of oil revenues during the three months ended June 30, 2006 was the result of (1) a larger amount of hedged volumes in 2006 of 337,000 Bbls as compared to 2007 of 268,000 Bbls and (2) a higher market price of NYMEX crude oil in 2006 of $70.65 per Bbl as compared to the 2007 price of $65.08 per Bbl. The effect of commodity price hedges in increasing gas revenues during the three months ended June 30, 2007 less than their effect of increasing gas revenues during the three months ended June 30, 2006 was the result of (1) a larger amount of hedged volumes in 2006 of 1,684,000 MMBtus as compared to 2007 of 1,647,000 MMBtus and (2) a lower reference market price of natural gas in 2006 of $5.55 per MMBtu as compared to the 2007 price of $6.59 per MMBtu.

Production expenses. Production expenses (including production taxes) were $12,206,000 ($1.67 per Mcfe) for the three months ended June 30, 2007, a $2,919,000 (31%) increase from $9,287,000 ($1.55 per Mcfe) for the three months ended June 30, 2006. The increase in production expenses is due to costs associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities. Lease operating expenses and workover costs comprised approximately 57% and 54% of production expenses for the three months ended June 30, 2007 and 2006, respectively. These costs per unit of production were $0.95 per Mcfe during the three months ended June 30, 2007, an increase of 12% from $0.85 per Mcfe during the three months ended June 30, 2006. This is primarily due to an increase in the cost of contract labor, storage tank maintenance, electrical work, and well service and repair. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 5% of lease operating expenses for both the three months ended June 30, 2007 and 2006.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 43% and 46% of production expenses during the three months ended June 30, 2007 and 2006, respectively. Production taxes per unit of production were $0.72 per Mcfe during the three months ended June 30, 2007, an increase of 1% from $0.71 per Mcfe during the three months ended June 30, 2006. This increase was primarily due to an increase in average natural gas equivalent prices received by the Company.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the three-month period ended June 30, 2007 and 2006:

	Three months ended June 30,	
(in thousands)	2007 (unaudited)	2006 (unaudited)
Geological and geophysical	$ 225	$ 163
Exploratory dry holes	5,635	329
Leasehold abandonments and other	4	3
Total exploration and abandonments	$5,864	$ 495

Our geological and geophysical expense, which primarily consists of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis, during the three months ended June 30, 2007 was $225,000, an increase of $62,000 from $163,000 for the three months ended June 30, 2006. This 38% increase is attributable to a core analysis purchased in the second quarter of 2007.

Our exploratory dry holes expense during the three months ended June 30, 2007 is primarily attributable to three operated exploratory wells that were unsuccessful. The costs associated with one of these wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $2.8 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.0 million. An additional $0.8 million was charged to exploratory dry hole costs relative to a target zone in the third of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which was determined to be dry. This well is currently being completed in a shallower zone which was found to be productive.

Our exploratory dry holes expense during the three months ended June 30, 2006 was attributable to one unsuccessful operated exploratory well located in Gaines County, Texas.

We had minimal leasehold abandonments during the three months ended June 30, 2007 and 2006.

Depreciation and depletion expense. Depreciation and depletion expense was $17,609,000 ($2.40 per Mcfe) for the three months ended June 30, 2007, an increase of $2,352,000 from $15,257,000 ($2.55 per Mcfe) for the three months ended June 30, 2006. The decrease in depreciation and depletion expense per Mcfe was primarily due to an increase in proved oil and natural gas reserves as a result of our successful development and exploratory drilling program.

Impairment of oil and gas properties. In accordance with SFAS No. 144 Accounting for the Impairment or Disposal of Long-Lived Assets, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during the three months ended June 30, 2007, we recognized a non-cash charge against earnings of $2,085,000, primarily related to a well drilled on acreage in Schleicher County, Texas. For the three months ended June 30, 2006, we recognized a non-cash charge against earnings of $2,978,000, 51% of which related to a property acquired in our Lowe Acquisition in December 2004 located in Pecos County, Texas and 33% related to a well drilled in Lea County, New Mexico.

Contract drilling fees stacked rigs. As discussed above under Items impacting comparability of our financial results Curtailment of drilling, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. As a result, for the drilling rigs that remained stacked, we recorded an expense during the three months ended June 30, 2007 of approximately $915,000 for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. These costs were minimized as one contractor secured work for a rig for 26 days during the quarter and charged us the difference between the current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

General and administrative expenses. General and administrative expenses were $7,629,000 ($1.04 per Mcfe) for the three months ended June 30, 2007, an increase of $4,476,000 (142%) from $3,153,000 ($0.53 per Mcfe) for the three months ended June 30, 2006. Excluding non-cash stock-based compensation of $1,128,000 during the three months ended June 30, 2007 and $329,000 during the three months ended June 30, 2006, general and administrative expenses would have been $6,501,000 ($0.89 per Mcfe) for the three months ended June 30, 2007, an increase of $3,677,000 (130%) from $2,824,000 ($0.47 per Mcfe) for the three months ended June 30, 2006. The increase in general and administrative expense during the three months ended June 30, 2007 was due (i) to the increase in the size and complexity of our operations following the combination transaction and related increase in professional fees, and (ii) annual bonuses in the aggregate amount of $2,529,000 paid to the officers and employees in April 2007 as approved by the Compensation Committee of the board of directors.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $221,000 and $188,000 during the three months ended June 30, 2007 and 2006, respectively. This revenue is reflected as a reduction of general and administrative expenses in the accompanying consolidated statements of operations.

Interest expense. Interest expense was $10,074,000 for the three months ended June 30, 2007, an increase of $1,870,000 from $8,204,000 for the three months ended June 30, 2006. The weighted average interest rate for the three months ended June 30, 2007 and 2006 was 7.8% and 7.3%, respectively. The weighted average debt balance during the three months ended June 30, 2007 and 2006 was approximately $506,147,000 and $454,435,000, respectively. The increase in interest expense was due to the increase in overall debt outstanding and an increase in interest rates. The increase in weighted average debt balance during the three months ended June 30, 2007 was primarily due to our borrowing under our revolving credit facility to fund our drilling activities.

Income tax provisions. We recorded an income tax expense of $3,988,000 and $4,566,000 for the three months ended June 30, 2007 and 2006, respectively. The income tax expense was due to the income reported during the three months ended June 30, 2007 and 2006. The effective income tax rate for the three months ended June 30, 2007 and 2006 was 40.2% and 37.5%, respectively.

We had a net deferred tax liability of $245,781,000 and $241,670,000 at June 30, 2007 and December 31, 2006, respectively. The net liability balance is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006. The net change is due to 2007 intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principles in the United States of America, partially offset by an increase in deferred hedge losses.

Six months ended June 30, 2007, compared to six months ended June 30, 2006

Oil and gas revenues. Revenue from oil and gas operations was $126,449,000 for the six months ended June 30, 2007, an increase of $49,079,000 (63%) from $77,370,000 for the six months ended June 30, 2006. This increase was primarily because of increased production as a result of the acquisition of the Chase Group Properties and secondarily due to successful drilling efforts during 2006 and 2007. Total production was 14,536 MMcfe for the six months ended June 30, 2007, an increase of 5,263 MMcfe (57%) from 9,273 MMcfe for the six months ended June 30, 2006. Total production during the six months ended June 30, 2007 was reduced by approximately 160 MMcfe as a result of the temporary shut-down of a natural gas processing plant through which we process and sell a portion of our production. See Items impacting comparability of our financial results Recent events. The increases in revenue and production attributable to the acquired Chase Group Properties between 2006 and 2007 were $26,600,000 and 3,259 MMcfe, respectively. In addition, average realized oil prices (after giving effect to hedging activities) were $57.33 per Bbl during the six months ended June 30, 2007, an increase of 1% from $56.56 per Bbl during the six months ended June 30, 2006; average realized natural gas prices (after giving effect to hedging activities) were $7.45 per Mcf during the six months ended June 30, 2007, an increase of 9% from $6.86 per Mcf during the six months ended June 30, 2006; and average realized natural gas equivalent prices (after giving effect to hedging activities) were $8.70 per Mcfe during the six months ended June 30, 2007, an increase of 4% from $8.34 per Mcfe during the six months ended June 30, 2006.

Hedging activities. The oil and gas prices that we report are based on the market price received for the commodities adjusted to give effect to the results of our cash flow hedging activities. We utilize commodity derivative instruments (swaps and zero cost collar option contracts) in order to (1) reduce the effect of the volatility of price changes on the commodities we produce and sell, (2) support our annual capital budgeting and expenditure plans and (3) lock-in commodity prices to protect economics related to certain capital projects. During the six months ended June 30, 2007, our commodity price hedges increased oil revenues by $244,000 ($0.17 per Bbl) and increased gas revenues by $187,000 ($0.03 per Mcf). During the six months ended June 30, 2006, our commodity price hedges decreased oil revenues by $4,394,000 ($4.92 per Bbl) and decreased gas revenues by $26,000 ($0.01 per Mcf).

The effect of the commodity price hedges in increasing oil revenues during the six months ended June 30, 2007 as compared to reducing oil revenues during the six months ended June 30, 2006 was the result of (1) increased hedged volumes from 400,000 Bbls in 2006 to 534,000 Bbls in 2007, (2) a decrease in the market price of NYMEX crude oil from an average of $67.02 per Bbl in 2006 to $61.70 per Bbl in 2007 and (3) a higher weighted average fixed price on the active derivative contracts of $62.10 in 2007 as compared to $58.52 in 2006. The effect of the commodity price hedges in increasing gas revenues during the six months ended June 30, 2007 as compared to reducing gas revenues during the six months ended June 30, 2006 was the result of (1) increased hedged volumes from 2,044,000 MMBtus in 2006 to 3,152,000 MMBtus in 2007, (2) a slight increase in the reference market price of natural gas from an average of $6.35 per MMBtu in 2006 to $6.46 per MMBtu in 2007 and (3) a higher weighted average floor price on the active zero cost collar option contracts of $5.98 in 2007 as compared to $5.53 in 2006.

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Production expenses. Production expenses (including production taxes) were $24,152,000 ($1.66 per Mcfe) for the six months ended June 30, 2007, an increase of $8,955,000 (59%) from $15,197,000 million ($1.64 per Mcfe) for the six months ended June 30, 2006. The increase in production expenses is from to two sources: (1) production expenses associated with the Chase Group Properties acquired in February 2006 of approximately $2,907,000 and (2) production expenses associated with new wells that were successfully completed in 2006 and 2007 as a result of our drilling activities. Lease operating expenses and workover costs comprised approximately 59% of production expenses for both the six months ended June 30, 2007 and 2006. These costs per unit of production were $0.98 per Mcfe during the six months ended June 30, 2007, an increase of 1% from $0.97 per Mcfe during the six months ended June 30, 2006. Lease operating expenses include ad valorem taxes that are affected by commodity price changes and ad valorem tax rates. Ad valorem taxes were approximately 7% and 5% of lease operating expenses for the six months ended June 30, 2007 and 2006, respectively.

The secondary component of production expenses is production taxes and is directly related to commodity price changes. These costs comprised approximately 41% of production expenses during both the six months ended June 30, 2007 and 2006. Production taxes per unit of production were $0.68 per Mcfe during the six months ended June 30, 2007, an increase of 2% from $0.67 per Mcfe during the six months ended June 30, 2006. This increase was primarily due to an increase in average natural gas equivalent prices received by the Company.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the six-month period ended June 30, 2007 and 2006:

	Six months ended June 30,	
(in thousands)	2007 (unaudited)	2006 (unaudited)
Geological and geophysical	$ 624	$1,035
Exploratory dry holes	5,665	363
Leasehold abandonments and other	16	3
Total exploration and abandonments	$6,305	$1,401

Our geological and geophysical expense, which primarily consists of general and administrative costs for our geology department as well as seismic data, geophysical data and core analysis, during the six months ended June 30, 2007 was $624,000, a decrease of $411,000 from $1,035,000 for the six months ended June 30, 2006. This 40% decrease is attributable to a data license and a core analysis purchased in the first quarter of 2006.

Our exploratory dry holes expense during the six months ended June 30, 2007 is primarily attributable to three operated exploratory wells that were unsuccessful. The costs associated with one of these wells drilled in the Western Delaware Basin in Culberson County, Texas approximated $2.8 million. Another of these wells, which was drilled in the Southeastern New Mexico Basin in Lea County, New Mexico, had costs of approximately $2.0 million. An additional $0.8 million was charged to exploratory dry hole costs relative to a target zone in the third of these wells in the Southeastern New Mexico Basin in Eddy County, New Mexico which was determined to be dry. This well is currently being completed in a shallower zone which was found to be productive.

Our exploratory dry holes expense during the six months ended June 30, 2006 was primarily attributable to one unsuccessful operated exploratory well located in Gaines County, Texas.

We had minimal leasehold abandonments during the six months ended June 30, 2007 and 2006.

Depreciation and depletion expense. Depreciation and depletion expense was $37,033,000 ($2.55 per Mcfe) for the six months ended June 30, 2007, an increase of $14,537,000 from $22,496,000 ($2.43 per Mcfe) for the six months ended June 30, 2006. The increase in depreciation and depletion expense and the increase in depreciation and depletion expense per Mcfe was primarily due to the acquisition of the Chase Group Properties and related acquisition costs associated with the combination transaction.

Impairment of oil and gas properties. In accordance with SFAS No. 144, we review our long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting. As a result of this review of the recoverability of the carrying value of our assets during the six months ended June 30, 2007, we recognized a non-cash charge against earnings of $3,198,000, 63% of which related to a well drilled on acreage in Schleicher County, Texas, and 12% of which related to a well drilled on acreage in Mountrail County, North Dakota. Of the total amount, $164,000 was related to the Chase Group Properties. For the six months ended June 30, 2006, we recognized a non-cash charge against earnings of $3,083,000, 50% of which related to a property acquired in our Lowe Acquisition in December 2004 located in Pecos County, Texas and 32% related to a well drilled on acreage in Lea County, New Mexico.

Contract drilling fees stacked rigs. As discussed above under Items impacting comparability of our financial results Curtailment of drilling, we determined in January 2007 to reduce our drilling activities for the first three months of 2007. As a result, we recorded an expense during the six months ended June 30, 2007 of approximately $4,269,000 for contract drilling fees related to stacked rigs subject to daywork drilling contracts with two drilling contractors. We resumed the majority of our planned drilling activities in April 2007 and all planned drilling activities in June 2007. These costs were minimized during the first six months of 2007 as one contractor secured work for a rig for 71 days during the six months and charged us the difference between the current operating day rate pursuant to the contract and the lower operating day rate received from the new customer.

General and administrative expenses. General and administrative expenses were $11,921,000 ($0.82 per Mcfe) for the six months ended June 30, 2007, a decrease of $291,000 (2%) from $12,212,000 ($1.32 per Mcfe) for the six months ended June 30, 2006. Excluding non-cash stock-based compensation of $1,953,000 during the six months ended June 30, 2007 and $6,951,000 during the six months ended June 30, 2006, general and administrative expenses would have been $9,968,000 ($0.69 per Mcfe) for the six months ended June 30, 2007, an increase of $4,707,000 (89%) from $5,261,000 ($0.57 per Mcfe) for the six months ended June 30, 2006. The increase in general and administrative expense during the six months ended June 30, 2007 was primarily due to the increase in the size and complexity of our operations following the combination transaction and related increase in professional fees. In addition, annual bonuses in the aggregate amount of $2,529,000 were paid to the officers and employees in April 2007 as compared to $907,000 aggregate bonuses paid to employees in February 2006, all of which were approved by the Compensation Committee of the board of directors.

We earn revenue as operator of certain oil and gas properties in which we own interests. As such, we earned revenue of $630,000 and $421,000 during the six months ended June 30, 2007 and 2006, respectively. This revenue is reflected as a reduction of general and administrative expenses in the consolidated statements of operations.

Interest expense. Interest expense was $20,749,000 for the six months ended June 30, 2007, an increase of $8,935,000 from $11,814,000 for the six months ended June 30, 2006. The weighted average interest rate for the six months ended June 30, 2007 and 2006 was 7.8% and 7.3%, respectively. The weighted average debt balance during the six months ended June 30, 2007 and 2006 was approximately $501,314,000 and $326,325,000, respectively. The increase in interest expense was due to the increase in overall debt outstanding and an increase in interest rates. The increase in weighted average debt balance during the six months ended June 30, 2007 was primarily due to our borrowing under our revolving credit facility to fund the cash portion of the combination transaction on February 27, 2006, and to fund our drilling activities.

Income tax provisions. We recorded income tax expense of $7,363,000 and $4,313,000 for the six months ended June 30, 2007 and 2006, respectively. The income tax expense was due to the income reported during the six months ended June 30, 2007 and 2006. The effective income tax rate for both the six months ended June 30, 2007 and 2006 was 41.1%.

We had a net deferred tax liability of $245,781,000 and $241,670,000 at June 30, 2007 and December 31, 2006, respectively. The net liability balance is primarily due to differences in basis and depletion of oil and gas properties for tax purposes as compared to book purposes related to the acquisition of the Chase Group Properties in February 2006. The net change is due to 2007 intangible drilling costs which are allowed by the Internal Revenue Service as deductions and are capitalized under generally accepted accounting principles in the United States of America, partially offset by an increase in deferred hedge losses.

Liquidity and capital resources

Our primary sources of liquidity for the six months ended June 30, 2007 have been cash flows generated from operating activities and financing provided by our bank credit facilities. As discussed in Items impacting comparability of our financial results Recent events, in August 2007 we received aggregate net proceeds of $173.2 million from the sale of common stock and utilized such proceeds to repay a portion of our outstanding indebtedness. We believe that funds from operating cash flows and our bank credit facilities should be sufficient to meet both our short-term working capital requirements and our revised 2007 exploration and development budget.

Cash flow from operating activities

Our net cash provided by operating activities was $63.6 million and $33.4 million for the six months ended June 30, 2007 and 2006, respectively. The increase in operating cash flows during the six months ended June 30, 2007 was principally due the increase in oil and gas sales, net of production costs for the six months ended June 30, 2007 as compared to the six months ended June 30, 2006, as a result of our successful development and exploratory drilling program and to the Chase Group Properties that we acquired in the combination transaction in February 2006.

Cash flow used in investing activities

During the six months ended June 30, 2007 and 2006, we invested $70.1 million and $497.4 million, respectively, for additions to, and acquisitions of, oil and gas properties, inclusive of dry hole costs. Cash flows used in investing activities were substantially higher during the six months ended June 30, 2006, primarily due to the $409 million cash portion of the consideration we paid to the Chase Group in the combination transaction. We determined to reduce our drilling activities and curtail capital expenditures during the three months ended March 31, 2007 until we were able to complete our second lien term loan facility in March 2007 in order to preserve liquidity. See Items impacting comparability of our financial results Curtailment of drilling above.

Cash flow from financing activities

Net cash provided by financing activities was $16.3 million and $455.3 million for the six months ended June 30, 2007 and 2006, respectively. Cash provided by financing activities in the six months ended June 30, 2006 was primarily due to borrowings under our revolving credit facility to fund the approximate $409 million cash portion of the consideration paid to the Chase Group pursuant to the combination transaction and proceeds from private issuances of equity in our company.

Bank credit facilities

We have two separate bank credit facilities. The first bank credit facility is our Credit Agreement, dated as of February 24, 2006, with JPMorgan Securities Inc. as the administrative agent for a group of lenders that provides a revolving line of credit having a maximum facility amount of $750 million, which we refer to as the revolving credit facility. The total amount that we can borrow and have outstanding at any one time is limited to the lesser of the maximum facility amount of $750 million or the borrowing base established by the lenders. As of June 30, 2007, the borrowing base under our revolving credit facility was $375 million. As of June 30, 2007, the principal amount outstanding under our revolving credit facility was $305.0 million. In February 2006, we incurred borrowings of approximately $421.0 million under our revolving credit facility in connection with the combination transaction to pay the cash purchase price of $400.0 million to the Chase Group, $15.9 million to repay the balance on the prior revolving credit facility of Concho Equity Holdings Corp. and approximately $5.1 million for bank fees and legal costs associated with our revolving credit facility. We also incurred borrowings of approximately $8.9 million in May 2006 in connection with the purchase of additional working interests in the Chase Group Properties pursuant to the combination transaction from persons associated with the Chase Group. The remaining borrowings under our revolving credit facility during 2006 and the six months ended June 30, 2007 were used for working capital and to fund a portion of our exploration and development drilling program.

The second bank credit facility is our Second Lien Credit Agreement, dated as of March 27, 2007, with Bank of America, N.A., as the administrative agent for the other lenders thereunder, that provides a five year term loan in the amount of $200.0 million, which we refer to as the second lien term loan facility. Upon execution of the second lien term loan facility, we funded the full amount under that facility and received proceeds of $199.0 million to repay the $39.8 million outstanding under our prior term loan facility, to reduce the outstanding balance under our revolving credit facility by $154.0 million and the remaining $5.2 million to pay loan fees, accrued interest and for general corporate purposes. As mentioned in Items impacting comparability of our financial results Recent Events, we repaid $86.6 million of this facility on August 9, 2007 with proceeds from our initial public offering of common stock.

Revolving credit facility. The revolving credit facility allows us to borrow, repay and reborrow amounts available under the revolving credit facility. The amount of the borrowing base is based primarily upon the estimated value of our oil and natural gas reserves. The borrowing base under our revolving credit facility is re-determined at least semi-annually. The revolving credit facility matures on February 24, 2010, and borrowings under our revolving credit facility bear interest, payable quarterly, at our option, at (1) a rate (as defined and further described in our revolving credit facility) per annum equal to a Eurodollar Rate (which is substantially the same as the London Interbank Offered Rate) for one, two, three or six months as offered by the lead bank under our revolving credit facility, plus an applicable margin ranging from 100 to 225 basis points, or (2) such bank s Prime Rate, plus an applicable margin ranging from 0 to 125 basis points, dependent in each case upon the percentage of our available borrowing base then utilized. Our revolving credit facility bore interest at 6.86% per annum as of June 30, 2007. We pay quarterly commitment fees under our revolving credit facility on the unused portion of the available borrowing base ranging from 25 to 50 basis points, dependent upon the percentage of our available borrowing base then utilized.

Borrowings under our revolving credit facility are secured by a first lien on substantially all of our assets and properties. Our revolving credit facility also contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers involving our company, incur liens and engage in certain other transactions without the prior consent of the lenders. The revolving credit facility also requires us to maintain certain ratios as defined and further described in our revolving credit facility, including a current ratio of not less than 1.0 to 1.0 and a maximum leverage ratio (generally defined as the ratio of total funded debt to a defined measure of cash flow) of no greater than 4.0 to 1.0. In addition, at the inception of the revolving credit facility, we had a one-time requirement to enter into hedging agreements with respect to not less than 75% of our forecasted production through December 31, 2008, that was attributable to our proved developed producing reserves estimated as of December 31, 2005. As of June 30, 2007, we were in compliance with all such covenants.

Second lien term loan facility. The second lien term loan facility provides a $200 million term loan, which bears interest, at our option, at (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 375 basis points or (2) the prime rate, plus an applicable margin of 225 basis points. Upon the completion of the equity offering on August 7, 2007, the interest rate under any of the second lien term loan facility outstanding increased, at our option, to (1) a rate per annum equal to the London Interbank Offered Rate, plus an applicable margin of 425 basis points or (2) the prime rate, plus an applicable margin of 275 basis points. We have the option to select different interest periods, subject to availability, and interest is payable at the end of the interest period we select, though such interest payments must be made at least on a quarterly basis. We are required to repay $500,000 of the second lien term loan facility on the last day of each calendar quarter, commencing June 30, 2007, until the remaining balance of the loan matures on March 27, 2012. Our second lien term loan facility bore interest at 9.10% per annum as of June 30, 2007. We have the right to prepay the outstanding balance under the second lien term loan facility at any time, provided, however, that we will incur a 2% prepayment penalty on any principal amount prepaid from March 27, 2008 until March 26, 2009 and a 1% prepayment penalty on any principal amount prepaid from March 27, 2009 until March 26, 2010. The prepayment made on August 9, 2007 was not subject to a prepayment penalty. As a result of the partial repayment of this facility on August 9, 2007, a pro rata portion of the deferred loan costs associated with our second lien term loan facility were written off to interest expense in August 2007 in the amount of approximately $1.0 million. Additionally, a pro rata portion of the unamortized original issue discount related to our second lien term loan facility was written off to interest expense in August 2007 in the amount of approximately $0.4 million.

Borrowings under the second lien term loan facility are secured by a second lien on the same assets as are securing our revolving credit facility, which liens are subordinated to liens securing our revolving credit agreement. The second lien term loan facility also contains various restrictive financial covenants and compliance requirements that are similar to those contained in the revolving credit agreement, including the maintenance of certain financial ratios.

Future capital expenditures and commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and gas properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations and that will allow us to apply our operating expertise or that otherwise have geologic characteristics that are similar to our existing properties.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $183 million for exploration and development expenditures during the year ending December 31, 2007 (including capital expenditures incurred through June 30, 2007) as follows:

(in millions)	**Amount**
Drilling and recompletion opportunities in our core operating area	$ 135.2
Projects in our emerging plays	28.9
Projects operated by third parties	14.2
Acquisition of leasehold acreage and other property interests	4.7

$ 183.0

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance and cash flows from operations and availability under our revolving credit facility will be sufficient to satisfy our 2007 exploration and development budget. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

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Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities, as amended. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments. We generally attempt to qualify such derivative instruments as cash flow hedges for accounting purposes.

We have utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts, we receive the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil or natural gas, as applicable, is less than the ceiling strike price and greater than the floor strike price, we receive the market price. If the market price of crude oil or natural gas, as applicable, exceeds the ceiling strike price or falls below the floor strike price, we receive the applicable collar strike price.

The tables below provide the volumes and related data associated with our oil and natural gas hedging as of June 30, 2007:

Oil and natural gas price collars

Period of time	Barrels of oil	NYMEX oil prices Floor	NYMEX oil prices Cap	MMBtus of natural gas	El Paso Natural Gas Permian Basin natural gas prices Floor	El Paso Natural Gas Permian Basin natural gas prices Cap	Fair market value
							(in thousands)
July 1, 2007 thru December 31, 2007	119,600	$ 37.95	$ 41.75		$	$	$ (3,467)
July 1, 2007 thru December 31, 2007		$	$	644,000	$ 5.00	$ 6.02	$ (458)
July 1, 2007 thru December 31, 2007		$	$	2,300,000	$ 6.25	$ 10.80	$ 1,482
January 1, 2008 thru December 31, 2008		$	$	4,941,000	$ 6.50	$ 9.35	$ (413)
Total net fair market value liability							$ (2,856)

Oil and natural gas price swaps

Period of time	Barrels of oil	NYMEX oil swap prices	MMBtus of natural gas	El Paso Natural Gas Permian Basin natural gas swap price	Fair market value

								(in thousands)
July 1, 2007 thru December 31, 2007				386,400	$	7.40	$	356
July 1, 2007 thru December 31, 2007	423,200	$	67.85				$	(1,417)
January 1, 2008 thru December 31, 2008	951,600	$	67.50				$	(4,403)
Total net fair market value liability							$	(5,464)

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Contractual obligations and commitments

We had the following contractual obligations and commitments as of June 30, 2007:

		Payments due by period			
(in thousands)	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	$505,000	$ 2,500	$309,000	$193,500	$
Operating lease obligation[2]	2,745	433	867	867	578
Daywork drilling contracts[3]	24,822	23,086	1,736		
Employment agreements with executive officers[4]	3,253	1,700	1,553		
Asset retirement obligations[5]	7,666	1,545	142	209	5,770
Total contractual cash obligations	$543,486	$29,264	$313,298	$194,576	$6,348

(1) See Note J *Long-term debt* to our consolidated financial statements.

(2) Operating lease obligation is for office space.

(3) Consists of daywork drilling contracts related to five drilling rigs contracted for a portion of 2007 and a portion of 2008. See Note K *Commitments and contingencies* to our consolidated financial statements.

(4) Represents amounts of cash compensation

we are obligated to pay to our executive officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted in the discretion of the board of directors.

(5) Amounts represent costs related to expected oil and gas property abandonments related to proved reserves by period, net of any future accretion.

Off-balance sheet arrangements

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

Critical accounting policies and practices

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

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

There have been no material changes in our critical accounting policies and procedures during the six months ended June 30, 2007. See our disclosure of critical accounting policies in the consolidated financial statements on Form S-1 for the year ended

December 31, 2006 contained in our Prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424 (b) on August 3, 2007.

Recent accounting pronouncements

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurement . This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement is effective for financial statements issued for fiscal years beginning after November 15, 2007. We will adopt SFAS No. 157 effective January 1, 2008. We are currently evaluating the impact of SFAS No. 157.

In February 2007, the FASB issued SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities, Including an Amendment of FASB Statement No. 115, (FAS 159) which will become effective in 2008. FAS 159 permits entities to measure eligible financial assets, financial liabilities and firm commitments at fair value, on an instrument-by-instrument basis, that are otherwise not permitted to be accounted for at fair value under other generally accepted accounting principles. The fair value measurement election is irrevocable and subsequent changes in fair value must be recorded in earnings. We will adopt this statement January 1, 2008, and we are currently evaluating if we will elect the fair value option for any of our eligible financial instruments and other items.

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

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have recently experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

Cautionary statement regarding forward-looking statements

This report may contain forward-looking statements within the meaning of Section 27 A of the Securities Act of 1933 and Section 21 E of the Securities Exchange Act of 1934 that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this quarterly report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this quarterly report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potent similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed in our Prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424 (b) on August 3, 2007, could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

§ business strategy;

- § estimated quantities of oil and natural gas reserves;
- § technology;
- § financial strategy;
- § oil and natural gas realized prices;
- § timing and amount of future production of oil and natural gas;
- § the amount, nature and timing of capital expenditures;
- § drilling of wells;
- § competition and government regulations;
- § marketing of oil and natural gas;
- § exploitation or property acquisitions;
- § costs of exploiting and developing our properties and conducting other operations;
- § general economic and business conditions;
- § cash flow and anticipated liquidity;
- § uncertainty regarding our future operating results; and
- § plans, objectives, expectations and intentions contained in this quarterly report that are not historical.

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

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

***Item 3.* QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Prospectus dated August 2, 2007 and filed with the SEC pursuant to Rule 424 (b) on August 3, 2007, as well as with the consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q.

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

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.

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 crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged approximately 75% of our forecasted oil and natural gas production through December 31, 2008, attributable to our proved developed producing reserves as of December 31, 2005, through the utilization of derivatives, including zero-cost collars and fixed price contracts. See Liquidity and capital resources Hedging. Because all of our futures contracts and swap agreements have been designated as hedge derivatives, changes in their fair value generally are reported as a component of accumulated other comprehensive income until the related sale of production occurs. At that time, the realized hedge derivative gain or loss is transferred to product revenues in the consolidated income statement.

Interest rate risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our bank credit facilities, and the terms of our revolving credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available borrowing base. We had total indebtedness of $305.0 million outstanding under our revolving credit facility at June 30, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $3.1 million and a corresponding decrease in net income before income tax. On March 27, 2007, we entered into a $200.0 million second lien term loan facility, from which we received $199.0 million in proceeds, with $39.8 million of such amount used to retire our prior second lien term loan facility, $154.0 million of such amount used to reduce the amount outstanding under our revolving credit facility and the remaining $5.2 million of such amount used to pay loan fees, accrued interest and for general corporate purposes. The impact of a 1% increase in interest rates on this amount of debt under our second lien term loan facility would result in increased interest expense of approximately $2.0 million and a corresponding decrease in net income before income tax.

Item 4. **CONTROLS AND PROCEDURES**

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of our disclosure controls and procedures pursuant to Rule 13a-15 under the Securities Exchange Act of 1934 as of the end of the period covered by this quarterly report. Based on that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2007, our disclosure controls and procedures were effective, in all material respects, to ensure that information we are required to disclose in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

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

PART II. OTHER INFORMATION

Item 1. Legal proceedings

Not applicable.

Item 1A. Risk factors

For a discussion of our potential risks and uncertainties, see the information under the heading Risk factors in our prospectus dated August 2, 2007, filed with the SEC in accordance with Rule 424(b) of the Securities Act on August 3, 2007, which is accessible on the SEC s website at www.sec.gov. There have been no material changes to the risk factors disclosed in the prospectus.

Item 2. Unregistered sales of equity securities and use of proceeds

On August 7, 2007, we completed our initial public offering of our common stock pursuant to our registration statement on Form S-1 (File 333-142315) declared effective by the SEC on August 1, 2007. The underwriters for the offering were J.P. Morgan Securities Inc., Banc of America Securities LLC, Lehman Brothers Inc., BNP Paribas Securities Corp., Merrill Lynch, Pierce, Fenner & Smith Incorporated, UBS Securities LLC and Wachovia Capital Markets, LLC. Pursuant to the registration statement, we registered the offer and sale of 24,020,173 shares of our $.001 par value common stock, which included 7,554,256 shares sold by certain selling stockholders and 3,133,066 shares subject to an option granted to the underwriters by the company to cover over-allotments. The underwriters exercised their over-allotment option on August 6, 2007. The sale of the shares in our initial public offering closed on August 7, 2007 and the sale of the shares covered by the over-allotment option closed on August 9, 2007. Our initial public offering terminated upon completion of the closing.

The gross proceeds of our initial public offering, including the gross proceeds from over-allotment option, based on the public offering price of $11.50 per share, were approximately $276.2 million, which resulted in net proceeds to the Company of $173.2 million after deducting underwriter discounts and commissions of approximately $17.3 million and other estimated expenses related to the offering of approximately $4.4 million and the net proceeds to the selling stockholders of approximately $81.3 million. We did not receive any proceeds from the sale of the shares by the selling stockholders. We also paid for legal fees incurred by the selling stockholders. Other than for such fees, no fees or expenses have been paid, directly or indirectly, to any officer, director or 10% stockholder or other affiliate. The net proceeds from our initial public offering were used to (i) retire outstanding borrowings under our second lien term loan facility on August 9, 2007 totaling $86.6 million and (ii) retire outstanding borrowings under our revolving credit facility on August 20, 2007 totaling $86.6 million.

Items 3. through 5.

Not applicable.

Item 6. Exhibits

Exhibit Number	Exhibit
3.1	Restated Certificate of Incorporation of Concho Resources Inc. (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K filed on August 8, 2007, and incorporated herein by reference)

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Exhibit Number	Exhibit
3.2	Amended and Restated Bylaws of Concho Resources Inc. (filed as Exhibit 3.2 to the Company s Current Report on Form 8-K filed on August 8, 2007, and incorporated herein by reference)
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1/A filed July 5, 2007, (File No. 333-142315), and incorporated herein by reference)
10.1	Transition Services Agreement dated April 23, 2007 between COG Operating LLC and Mack Energy Corporation (filed as Exhibit 10.3 to the Company s Registration Statement on Form S-1 filed April 24, 2007, (File No. 333-142315), and incorporated herein by reference)
10.2	Indemnification Agreement dated August 21, 2007, by and between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.3	Indemnification Agreement dated August 21, 2007, by and between Concho Resources Inc. and Ray M. Poage (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.4	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.3 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.5	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.4 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.6	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and David W. Copeland (filed as Exhibit 10.5 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.7	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and Curt F. Kamradt (filed as Exhibit 10.6 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.8	First Amendment to Employment Agreement, dated August 21, 2007, by and between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.7 to the Company s Current Report on Form 8-K filed on August 24, 2007, and incorporated herein by reference)
10.9	First Amendment to Employment Agreement, dated August 31, 2007, by and between Concho Resources Inc. and David M. Thomas III
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

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

CONCHO RESOURCES INC.

Date: September 7, 2007

By /S/ Timothy A. Leach

Timothy A. Leach
Chairman and Chief Executive Officer

By /S/ Curt F. Kamradt

Curt F. Kamradt
Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)