Approach Resources Inc
Form 10-Q
November 03, 2010

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

(Mark One)

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

For the quarterly period ended September 30, 2010

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: 001-33801

APPROACH RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**51-0424817**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
One Ridgmar Centre **6500 West Freeway, Suite 800** **Fort Worth, Texas**	**76116**
(Address of principal executive offices)	(Zip Code)

(817) 989-9000

(Registrant s telephone number, including area code)

N/A

(Former name, former address and former fiscal year, if changed since last report)

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

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

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

Large accelerated filer o	Accelerated filer þ	Non-accelerated filer o (Do not check if smaller reporting company)	Smaller reporting company o

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

The number of shares of the registrant s common stock, $0.01 par value, outstanding as of October 31, 2010 was 21,531,094.

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PART I FINANCIAL INFORMATION

Item 1. Financial Statements.

Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Balance Sheets
(In thousands, except shares and per-share amounts)

	September 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 417	$ 2,685
Accounts receivable:		
Joint interest owners	7,960	3,088
Oil and gas sales	4,873	4,607
Unrealized gain on commodity derivatives	1,232	786
Prepaid expenses and other current assets	291	582
Deferred income taxes current	1,815	255
Total current assets	16,588	12,003
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	438,302	387,792
Furniture, fixtures and equipment	2,193	1,540
	440,495	389,332
Less accumulated depletion, depreciation and amortization	(101,296)	(84,849)
Net properties and equipment	339,199	304,483
OTHER ASSETS	2,521	2,440
Total assets	$ 358,308	$ 318,926
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Advances from nonoperators	$ 848	$ 2,689
Accounts payable	9,095	3,074
Oil and gas sales payable	6,072	3,774
Accrued liabilities	12,228	10,935
Unrealized loss on commodity derivatives		1,524
Total current liabilities	28,243	21,996

NONCURRENT LIABILITIES:		
Long-term debt	51,069	32,319
Unrealized loss on commodity derivatives	232	1,144
Deferred income taxes	43,979	38,374
Asset retirement obligations	5,120	4,597
Total liabilities	128,643	98,430
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY:		
Preferred stock, $0.01 par value, 10,000,000 shares authorized, none outstanding		
Common stock, $0.01 par value, 90,000,000 shares authorized, 21,527,145 and 20,959,285 issued and outstanding, respectively	215	209
Additional paid-in capital	170,958	168,993
Retained earnings	58,725	51,524
Accumulated other comprehensive loss	(233)	(230)
Total stockholders equity	229,665	220,496
Total liabilities and stockholders equity	$ 358,308	$ 318,926

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Statements of Operations
(In thousands, except shares and per-share amounts)

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
REVENUES:				
Oil and gas sales	$ 14,916	$ 8,787	$ 41,291	$ 28,767
EXPENSES:				
Lease operating	1,995	1,894	6,038	6,016
Severance and production taxes	743	455	2,047	1,392
Exploration	568	534	2,245	534
General and administrative	3,212	2,237	7,902	7,277
Depletion, depreciation and amortization	5,832	5,595	16,677	18,766
Total expenses	12,350	10,715	34,909	33,985
OPERATING INCOME (LOSS)	2,566	(1,928)	6,382	(5,218)
OTHER:				
Interest expense, net	(615)	(451)	(1,631)	(1,353)
Realized gain on commodity derivatives	1,615	4,271	3,613	11,896
Unrealized (loss) gain on commodity derivatives	(312)	(6,414)	2,882	(8,589)
INCOME (LOSS) BEFORE INCOME TAX PROVISION (BENEFIT)	3,254	(4,522)	11,246	(3,264)
INCOME TAX PROVISION (BENEFIT)	1,167	(1,378)	4,045	(317)
NET INCOME (LOSS)	$ 2,087	$ (3,144)	$ 7,201	$ (2,947)
EARNINGS (LOSS) PER SHARE:				
Basic	$ 0.10	$ (0.15)	$ 0.34	$ (0.14)
Diluted	$ 0.10	$ (0.15)	$ 0.34	$ (0.14)
WEIGHTED AVERAGE SHARES OUTSTANDING:				
Basic	21,357,682	20,929,508	21,139,089	20,839,746
Diluted	21,484,465	20,929,508	21,265,794	20,839,746

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Statements of Cash Flows
(In thousands)

	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
OPERATING ACTIVITIES:		
Net income (loss)	$ 7,201	$ (2,947)
Adjustments to reconcile net income (loss) to cash provided by operating activities:		
Depletion, depreciation and amortization	16,677	18,766
Unrealized (gain) loss on commodity derivatives	(2,882)	8,589
Exploration expense	2,245	534
Share-based compensation expense	2,043	1,434
Deferred income taxes	3,974	(314)
Changes in operating assets and liabilities:		
Accounts receivable	(5,053)	16,019
Prepaid expenses and other assets	477	99
Accounts payable	4,182	(10,315)
Oil and gas sales payable	2,298	(1,888)
Accrued liabilities	1,293	(7,047)
Cash provided by operating activities	32,455	22,930
INVESTING ACTIVITIES:		
Additions to oil and gas properties	(52,385)	(18,993)
Additions to other property and equipment, net	(730)	(475)
Cash used in investing activities	(53,115)	(19,468)
FINANCING ACTIVITIES:		
Borrowings under credit facility, net of debt issuance costs	81,046	55,677
Repayment of amounts outstanding under credit facility	(62,650)	(62,525)
Cash provided by (used in) financing activities	18,396	(6,848)
CHANGE IN CASH AND CASH EQUIVALENTS	(2,264)	(3,386)
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	(4)	9
CASH AND CASH EQUIVALENTS, beginning of period	2,685	4,077
CASH AND CASH EQUIVALENTS, end of period	$ 417	$ 700

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:

Cash paid for interest	$ 1,524	$ 1,199

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries
Unaudited Consolidated Statements of Comprehensive Income (Loss)
(In thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ 2,087	$ (3,144)	$ 7,201	$ (2,947)
Other comprehensive (loss) income:				
Foreign currency translation, net of related income tax	(3)	111	(3)	202
Total comprehensive income (loss)	$ 2,084	$ (3,033)	$ 7,198	$ (2,745)

See accompanying notes to these consolidated financial statements.

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

Approach Resources Inc. (the Company, we, us or our) is an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties in the United States. The Company s core operations, production and reserve base are located in the Permian Basin in West Texas. The Company targets multiple oil and liquids-rich formations in the Permian Basin, where we operate approximately 98,000 net acres.

Consolidation, Basis of Presentation and Significant Estimates

The interim consolidated financial statements of the Company are unaudited and contain all adjustments (consisting primarily of normal recurring accruals) necessary for a fair statement of the results for the interim periods presented. Results for interim periods are not necessarily indicative of results to be expected for a full year due in part to the volatility in prices for crude oil and natural gas, future commodity prices for commodity derivative contracts, global economic and financial market conditions, interest rates, access to sources of liquidity, estimates of reserves, drilling risks, geological risks, transportation restrictions, the timing of acquisitions, product supply and demand, market competition and interruptions of production. You should read these consolidated interim financial statements in conjunction with the audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the Securities and Exchange Commission on March 12, 2010.

The accompanying interim consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and include the accounts of the Company and its wholly-owned subsidiaries. Intercompany accounts and transactions are eliminated. In preparing the accompanying financial statements, we have made certain estimates and assumptions that affect reported amounts in the financial statements and disclosures of contingencies. Actual results may differ from those estimates. Significant assumptions are required in the valuation of proved oil and natural gas reserves, which affect the amount at which oil and natural gas properties are recorded. Significant assumptions are also required in estimating our accrual of capital expenditures, asset retirement obligations and share-based compensation. It is at least reasonably possible these estimates could be revised in the near term, and these revisions could be material. Certain prior year amounts have been reclassified to conform to current year presentation. These classifications have no impact on the net income reported.

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

2. Earnings Per Common Share

We report basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities unless their impact is antidilutive. The following are reconciliations of the numerators and denominators of our basic and diluted earnings per share (dollars in thousands, except per-share amounts):

	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Income (numerator):				
Net income (loss) basic	$ 2,087	$ (3,144)	$ 7,201	$ (2,947)
Weighted average shares (denominator):				
Weighted average shares basic	21,357,682	20,929,508	21,139,089	20,839,746
Dilution effect of share-based compensation, treasury method	126,783	(1)	126,705	(1)
Weighted average shares diluted	21,484,465	20,929,508	21,265,794	20,839,746
Net income (loss) per share:				
Basic	$ 0.10	$ (0.15)	$ 0.34	$ (0.14)
Diluted	$ 0.10	$ (0.15)	$ 0.34	$ (0.14)

(1) Approximately 416,000 stock options were excluded from assumed conversions because they were anti-dilutive for the three and nine months ended September 30, 2009.

3. Revolving Credit Facility

We have a $200 million revolving credit facility with a borrowing base set at $115 million at September 30, 2010. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

The maturity date under our revolving credit facility is July 31, 2012. Borrowings bear interest based on the agent bank s prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

Effective February 1, 2010, we entered into a seventh amendment to our credit agreement, which replaced The Frost National Bank as the administrative agent under the credit agreement with JPMorgan Chase Bank, N.A., as successor agent.

Effective May 3, 2010, we entered into an eighth amendment to our credit agreement, which (i) extended the maturity date of the credit agreement by one year to July 31, 2012, (ii) increased the Company s commodity derivatives limit from 75% to 85% of annual projected production from proved developed producing oil and gas properties, (iii) reaffirmed the borrowing base and lenders aggregate commitment of $115 million and (iv) transferred Fortis Capital Corp. s interest in the credit agreement to BNP Paribas.

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

Effective October 21, 2010, we entered into a ninth amendment to our credit agreement, which increased the borrowing base and lenders aggregate commitment under the credit agreement to $150 million from $115 million.

We had outstanding borrowings of $51.1 million and $32.3 million under our revolving credit facility at September 30, 2010 and December 31, 2009, respectively. The weighted average interest rate applicable to our outstanding borrowings was 3.50% and 3.20% as of September 30, 2010, and December 31, 2009, respectively. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at September 30, 2010, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.
- a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 3.5 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes, and (7) certain other noncash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or nonrecurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At September 30, 2010, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

4. Commitments and Contingencies

Approach Operating, LLC v. EnCana Oil & Gas (USA) Inc., Cause No. 29.070A, District Court of Limestone County, Texas. On July 2, 2009, our operating subsidiary filed a lawsuit against EnCana Oil & Gas (USA) Inc. (EnCana) for breach of the joint operating agreement (JOA) covering our North Bald Prairie project in East Texas and seeking damages for nonpayment of amounts owed under the JOA as well as declaratory relief. We contend that such amounts owed by EnCana were $2 million and $2.1 million at September 30, 2010, and December 31, 2009, respectively, plus attorneys fees, costs and other amounts to which we might be entitled under law or in equity. The amount owed to us is included in other noncurrent assets on our balance sheet at September 30, 2010, and December 31, 2009. As we previously have disclosed, in December 2008, EnCana notified us that it was exercising its right to become operator of record for joint interest wells in North Bald Prairie under an operator election agreement between the parties. EnCana contends that it does not owe us for part or all of joint interest billings incurred after EnCana provided us with notice of EnCana s election to assume operatorship in December 2008. EnCana also alleges that certain of the disputed operations were unnecessary, and that other charges are improper because we allegedly failed to obtain EnCana s consent under the JOA prior to undertaking the operations. We have informed the court that we will transfer operatorship to EnCana when EnCana has made all payments it owes under the JOA.

We also are involved in various other legal and regulatory proceedings arising in the normal course of business. While we cannot predict the outcome of these proceedings with certainty, we do not believe that an adverse result in any pending legal or regulatory proceeding, individually or in the aggregate, would be material to our consolidated financial condition or cash flows; however, an unfavorable outcome could have a material adverse effect on our results of operations for a specific interim period or year.

5. Income Taxes

The effective income tax rate for the three and nine months ended September 30, 2010, was 35.9% and 36.0%, respectively. Total income tax expense for the three and nine months end September 30, 2010, differed from amounts computed by applying the U.S. federal statutory tax rates to pretax income due primarily to state taxes and the impact of permanent differences between book and taxable income.

Total income tax expense for the three and nine months ended September 30, 2009, was 30.5% and 9.7%, respectively. Total income tax benefit for the three and nine months ended September 30, 2009, differed from the amounts computed by applying the U.S. federal statutory tax rates to pretax income due primarily to state taxes and the impact of permanent differences between book and taxable income. The total income tax expense for the nine months ended September 30, 2009, also was impacted by a change in our estimated income tax expense for the year ended December 31, 2008, and increased state income tax rates.

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

6. Derivatives

At September 30, 2010, we had the following commodity derivatives positions outstanding:

Period	Volume (MMBtu) Monthly	Total	$/MMBtu Fixed
NYMEX Henry Hub			
Price swaps 2010	150,000	450,000	$ 5.85
Price swaps 2010	150,000	450,000	$ 6.40
Price swaps 2010	100,000	300,000	$ 6.36
Weighted average price ($/MMBtu)			$ 6.18
WAHA basis differential			
Basis swaps 2010	415,000	1,245,000	$ (0.71)
Basis swaps 2011	300,000	3,600,000	$ (0.53)

The following summarizes the fair value of our open commodity derivatives as of September 30, 2010, and December 31, 2009 (in thousands):

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	September 30, 2010	December 31, 2009	Balance Sheet Location	September 30, 2010	December 31, 2009
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives	$ 1,232	$ 786	Unrealized loss on commodity derivatives	$ 232	$ 2,668

The following summarizes the impact of our commodity derivatives on our consolidated statement of operations (in thousands):

		Asset Derivatives			
		Three Months Ended		Nine Months Ended	
	Income Statement Location	September 30, 2010	2009	September 30, 2010	2009
Derivatives not designated as hedging instruments under SFAS 133					
Commodity derivatives	Realized gain on commodity derivatives	$ 1,615	$ 4,271	$ 3,613	$ 11,896

Unrealized (loss) gain on commodity derivatives	(312)	(6,414)	2,882	(8,589)
	$ 1,303	$ (2,143)	$ 6,495	$ 3,307

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in net income as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

We are exposed to credit losses in the event of nonperformance by the counterparties on our commodity derivatives positions and have considered the exposure in our internal valuations. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions.

To estimate the fair value of our commodity derivatives positions, we use market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and attempt to use the best available information. We determine the fair value based upon the hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and lowest priority to unobservable inputs (Level 3 measurement). The three levels of fair value hierarchy are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. At September 30, 2010, we had no Level 1 measurements.

Level 2 Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Our derivatives, which consist primarily of commodity swaps, are valued using commodity market data which is derived by combining raw inputs and quantitative models and processes to generate forward curves. Where observable inputs are available, directly or indirectly, for substantially the full term of the asset or liability, the instrument is categorized in Level 2. At September 30, 2010, all of our commodity derivatives were valued using Level 2 measurements.

Level 3 Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management s best estimate of fair value. At September 30, 2010, we had no Level 3 measurements.

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Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
September 30, 2010

7. Share-Based Compensation

During the nine months ended September 30, 2010, we granted 141,139 shares of common stock to employees. The total fair market value of these shares on the grant date was $1.1 million, which will be expensed over a service period of three years. In August 2010, we made an additional grant of 400,000 shares to our executive officers. The total fair market value of these shares on the grant date was $2.7 million, which will be expensed over a service period of approximately five years, subject to certain performance restrictions. A summary of the status of shares for the nine months ended September 30, 2010, is presented below:

	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2010	225,880	$ 9.73
Granted	541,139	7.01
Vested	(74,496)	10.01
Cancelled	(5,897)	10.09
Nonvested at September 30, 2010	686,626	$ 7.56

During the nine months ended September 30, 2010, approximately 42,000 shares were granted to nonemployee directors with a fair market value of $337,000, which is expensed on the date of grant.

8. Subsequent Event

In October 2010, we acquired an additional 10% working interest in Cinco Terry (northwest portion of Project Pangea) from a non-operating partner for $21.5 million. The acquisition included 1.9 MMBoe of estimated proved reserves (60% oil and NGLs and 61% proved developed), 470 Boe/d of production and 5,033 net acres.

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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 in understanding our results of operations and our financial condition. This section should be read in conjunction with management s discussion and analysis contained in our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the Securities and Exchange Commission (SEC) on March 12, 2010. Our consolidated financial statements and the accompanying notes included elsewhere in this Quarterly Report on Form 10-Q contain additional information that should be referred to when reviewing this material. Certain statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, which could cause actual results to differ from those expressed in this report. A glossary containing the meaning of the oil and gas industry terms used in this management s discussion and analysis follows the Results of Operations table in this Item 2.

Forward-Looking Statements and Cautionary Statements

Various statements in this report, including those that express a belief, expectation or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). The forward-looking statements may include projections and estimates concerning the timing and success of specific projects, typical well economics and our future reserves, production, resource potential, revenues, costs, income, capital spending, 3-D seismic operations, interpretation and results and obtaining permits and regulatory approvals. When used in this report, the words will, believe, intend, expect, may, should, anticipa estimate, plan, predict, project or their negatives, other similar expressions or the statements that include those wor are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

These forward-looking statements are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management s assumptions about future events may prove to be inaccurate. We caution all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to the factors listed in the Risk Factors section and elsewhere in this report. All forward-looking statements speak only as of the date of this report. We expressly disclaim all responsibility to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. The risks, contingencies and uncertainties relate to, among other matters, the following:

- our business strategy, including our ability to recover oil and gas in place associated with our Wolffork oil resource play in the Permian Basin;
- estimated quantities of oil and gas reserves;
- overall United States and global economic and financial market conditions;
- domestic and foreign demand and supply for oil, gas, NGLs and LNG;
- uncertainty of commodity prices in oil, gas and NGLs;
- disruption of credit and capital markets;
- our financial position;

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- our cash flow and liquidity;
- replacing our oil and gas reserves;
- our inability to retain and attract key personnel;
- uncertainty regarding our future operating results;
- uncertainties in exploring for and producing oil and gas;
- high costs, shortages, delivery delays or unavailability of drilling rigs, equipment, labor or other services;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our gas and NGLs and other processing and transportation considerations;
- our inability to obtain additional financing necessary to fund our operations and capital expenditures and to meet our other obligations;
- competition in the oil and gas industry;
- marketing of oil, gas and NGLs;
- interpretation of 3-D seismic data;
- exploitation of our current asset base or property acquisitions;
- the effects of government regulation and permitting and other legal requirements;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- other factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 12, 2010, our Quarterly Report on Form 10-Q for the three months ended June 30, 2010, filed with the SEC on August 4, 2010, and factors discussed herein.

Our financial results depend upon many factors, particularly the price of oil, gas and NGLs. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, estimates of inventory storage levels, commodity price differentials and other factors. Factors potentially impacting the future natural gas supply balance include increased drilling and production from domestic, shale gas reservoirs and the recent increase in the United States LNG import and export capacity. We cannot accurately predict future oil, gas and NGL prices, and therefore, we cannot determine what effect price increases or decreases will have on our capital program, production volumes and future revenues. A substantial or extended decline in oil, gas or NGL prices could have a material adverse effect on our business, financial condition, results of operations, quantities of oil, gas and NGL reserves that may be economically produced and liquidity that may be accessed through our borrowing base under our revolving credit facility and through the capital markets. We generally enter into natural gas financial swaps and collars to partially mitigate the risk of market price fluctuations related to future oil and gas production. However, because of consistently soft natural gas prices and weak forward markets during 2010, we have not entered into derivatives contracts for any natural gas production beyond 2010. We will continue to monitor the forward commodity markets to look for opportunities to mitigate risk for our expected oil, gas and NGL production.

In addition to production volumes and commodity prices, finding and developing sufficient amounts of oil and gas reserves at economical costs are critical to our long-term success. Future finding and development costs are subject to changes in the industry, including the costs of acquiring, drilling and completing our projects. We focus on increasing oil and gas reserves and production while controlling costs at a level that is appropriate for our long-term operations. Our future cash flow from operations will depend on our ability to manage our overall cost structure.

Like all oil and gas production companies, we face the challenge of natural production declines. Oil and gas production from a given well naturally decreases over time. Additionally, our reserves have a rapid initial decline. We generally will attempt to overcome this natural decline by drilling to develop and

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identify additional reserves, acquisitions, and farm-ins or other joint drilling ventures. However, during times of severe price declines, we may from time to time reduce capital expenditures and curtail drilling operations in order to preserve net asset value of our existing proved reserves. A material reduction in capital expenditures and drilling activities could materially reduce our production volumes and revenues and increase future expected costs necessary to develop existing reserves. Notwithstanding these periods of reduced capital expenditures or curtailed production, our future growth will depend upon our ability over the long term to continue to add oil and gas reserves in excess of production at a reasonable cost. We intend to maintain our focus on the costs of adding reserves through drilling and acquisitions as well as the costs necessary to produce such reserves.

We also face the challenge of financing our future exploration and drilling program and any acquisitions. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for temporary working capital needs and maintenance of our traditional Canyon Sands development drilling program. Funding for future expansion of our drilling program or future acquisitions may require additional sources of equity and debt financing, which may not be available.

Overview

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and gas properties. We focus on oil and natural gas reserves in tight sands and shale. Our management and technical team has a proven track record of finding and exploiting reservoirs through advanced completion, fracturing and drilling techniques. Our properties are primarily located in Texas, including the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger) and the East Texas Basin in East Texas (Cotton Valley Sand and Cotton Valley Lime). We also have exploratory projects in Northern New Mexico targeting the Mancos Shale and Western Kentucky targeting the New Albany Shale.

At June 30, 2010, we had estimated proved oil and gas reserves of 46.4 MMBoe. Our reserve base is 50% oil and NGLs, 50% natural gas and 48% proved developed. Over 95% of our proved reserves and production are located in the Permian Basin. As the operator of all of our estimated proved reserves and production, we have a high degree of control over capital expenditures and other operating matters.

Our core operating area is in the Permian Basin in Crockett and Schleicher Counties, Texas. We operate two fields, Ozona Northeast and Cinco Terry. During the first nine months of 2010, we acquired 28,994 net acres and connected Ozona Northeast and Cinco Terry into one project area that we have called Project Pangea. Project Pangea is approximately 98,000 net, primarily contiguous acres and is characterized by multiple oil and liquids-rich formations.

During the three months ended September 30, 2010, we produced 2.5 Bcfe, or 27.3 MMcfe/d. We drilled 27 gross (15 net) wells in the Permian Basin during the three months ended September 30, 2010, of which five gross (four net) wells were waiting on completion at September 30, 2010. At September 30, 2010, we owned working interests in approximately 550 producing oil and gas wells.

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Recent Developments

We recently announced the results of a detailed geological and petrophysical study of the Wolfcamp and Clearfork (Wolffork) formations across Project Pangea. We identified the Wolffork through extensive regional mapping, using whole-core data, 3-D seismic data from over 135,000 acres and well data from over 400 wellbores that we have drilled and completed while targeting the deeper Canyon Sands, Strawn and Ellenburger zones. The Wolffork is comprised of three stacked pay zones, the Clearfork, Dean and Wolfcamp Shale formations. Petrophysical analyses indicate more than 2,500 feet of gross pay from the Wolffork. To date, we have recompleted three wells in the Wolfcamp Shale, and commingled the Wolfcamp Shale and Canyon Sands in another well. During the fourth quarter of 2010, we plan to further delineate the Wolffork trend across our acreage position. Our Wolffork pilot program for the balance of 2010 is outlined below.

Drill one horizontal well, the Cinco Terry M 901-H, targeting the Wolfcamp Shale. We expect to complete the horizontal well during the first quarter of 2011.

Recomplete the Cinco Terry 1601, targeting the Wolfcamp Shale zone.

Recomplete two wells in Ozona Northeast (southeast portion of Project Pangea), targeting the Wolffork.

Complete the Baker C 1201, targeting the Wolffork and Canyon Sands zones.

In October 2010, we acquired an additional 10% working interest in Cinco Terry (northwest portion of Project Pangea) from a non-operating partner for $21.5 million. The acquisition included 1.9 MMBoe of estimated proved reserves (60% oil and NGLs and 61% proved developed), 470 Boe/d of production and 5,033 net acres. Project Pangea now covers approximately 98,000 net acres that we believe is prospective for one or more of the Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger formations.

In October 2010, we entered into a ninth amendment to our credit agreement, which increased the borrowing base and lenders aggregate commitment under our credit agreement to $150 million from $115 million, based on our mid-year 2010 proved reserves.

Results of Operations

The following table sets forth summary information regarding natural gas, oil and NGL revenues, production, average product prices and average production costs and expenses for the three and nine months ended September 30, 2010 and 2009. Oil and NGLs are converted at the rate of one Bbl per six Mcf of natural gas.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	**2009**	**2010**	**2009**
Revenues (in thousands)				
Gas	$ 7,216	$ 5,001	$ 21,762	$ 16,936
Oil	5,135	2,490	12,630	7,700
NGLs	2,565	1,296	6,899	4,131
Total oil and gas sales	14,916	8,787	41,291	28,767
Realized gain on commodity derivatives	1,615	4,271	3,613	11,896
Total oil and gas sales including derivative impact	$ 16,531	$ 13,058	$ 44,904	$ 40,663

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	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
Production				
Gas (MMcf)	1,664	1,505	4,646	4,900
Oil (MBbls)	71	39	172	155
NGLs (MBbls)	70	44	174	164
Total (MMcfe)	2,511	2,003	6,723	6,817
Total (MMcfe/d)	27.3	21.8	24.6	25.0
Average prices				
Gas (per Mcf)	$ 4.34	$ 3.32	$ 4.68	$ 3.46
Oil (per Bbl)	72.19	63.49	73.41	49.53
NGLs (per Bbl)	36.65	29.72	39.64	25.18
Total (per Mcfe)	$ 5.94	$ 4.39	$ 6.14	$ 4.22
Realized gain on commodity derivatives (per Mcfe)	0.64	2.13	0.54	1.75
Total including derivative impact (per Mcfe)	$ 6.58	$ 6.52	$ 6.68	$ 5.97
Costs and expenses (per Mcfe)				
Lease operating (1)	$ 0.79	$ 0.95	$ 0.90	$ 0.88
Severance and production taxes	0.30	0.23	0.30	0.20
Exploration	0.23	0.27	0.33	0.08
General and administrative	1.28	1.12	1.18	1.07
Depletion, depreciation and amortization	2.32	2.79	2.48	2.75

(1) Lease operating expenses per Mcfe include ad valorem taxes.

Glossary

Bbl. One stock tank barrel, of 42 U.S. gallons liquid volume, used herein to reference oil, condensate or NGLs.

LNG.

	Liquid natural gas.
MBbl.	Thousand barrels of oil, condensate or NGLs.
Mcf.	Thousand cubic feet of natural gas.
Mcfe.	Thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs.
MMBoe.	Million barrels of oil equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs.
MMcf.	Million cubic feet of natural gas.
MMcfe.	Million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of oil, condensate or NGLs.
NGLs.	Natural gas liquids.

/d.

Per day when used with volumetric units or dollars.

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Three Months Ended September 30, 2010, Compared to Three Months Ended September 30, 2009

Oil and gas production. Production for the three months ended September 30, 2010, totaled 2.5 Bcfe (27.3 MMcfe/d), compared to 2 Bcfe (21.8 MMcfe/d) produced in the prior year period, an increase of 25.4%. Production for the three months ended September 30, 2010, was 66% natural gas and 34% oil and NGLs, compared to 75% natural gas and 25% oil and NGLs in the prior year period.

Oil and gas sales. Oil and gas sales increased $6.1 million, or 69.8%, for the three months ended September 30, 2010, to $14.9 million from $8.8 million for the three months ended September 30, 2009. The increase in oil and gas sales principally resulted from an increase in production volumes and higher realized oil and gas prices. The increase in production volumes is a result of our continued development in Cinco Terry.

Commodity derivative activities. Our commodity derivative activity resulted in a realized gain of $1.6 million and $4.3 million for the three months ended September 30, 2010, and 2009, respectively. Our average realized price, including the effect of commodity derivatives, was $6.58 per Mcfe for the three months ended September 30, 2010, compared to $6.52 per Mcfe for the three months ended September 30, 2009. Realized gains and losses on commodity derivatives are derived from the relative movement of gas prices in relation to the fixed notional pricing in our price swaps for the applicable periods. The unrealized loss on commodity derivatives was $312,000 and $6.4 million for the three months ended September 30, 2010, and 2009, respectively. As natural gas commodity prices increase, the fair value of the open portion of those positions decreases. As natural gas commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in net income on our consolidated statements of operations under the caption entitled unrealized (loss) gain on commodity derivatives.

Lease operating expenses. Our lease operating expenses (LOE) increased $101,000, or 5.3%, for the three months ended September 30, 2010, to $2 million ($0.79 per Mcfe) from $1.9 million ($0.95 per Mcfe) for the three months ended September 30, 2009. The decrease in LOE per Mcfe over the prior year period was primarily due to an increase in production over the prior year period. The following is a summary of LOE (per Mcfe):

	Three Months Ended September 30,			
	2010	**2009**	**Change**	**% Change**
Compression and gas treating	$ 0.24	$ 0.26	$ (0.02)	(7.7)%
Water hauling, insurance and other	0.19	0.18	0.01	5.6
Ad valorem taxes	0.18	0.18		
Pumping and supervision	0.13	0.18	(0.05)	(27.8)
Well repairs and maintenance	0.04	0.14	(0.10)	(71.4)
Workovers	0.01	0.01		
Total	$ 0.79	$ 0.95	$ (0.16)	(16.8)%

Severance and production taxes. Our severance and production taxes increased $288,000, or 63.3%, for the three months ended September 30, 2010, to $743,000 from $455,000 for the three months ended September 30, 2009. The increase in severance and production taxes was primarily due to the increase in oil and gas sales between the two periods. Severance and production taxes amounted to approximately 5.0% and 5.2% of oil and gas sales for the respective periods.

Exploration. We recorded $568,000 and $534,000 of exploration expense for the three months ended September 30, 2010 and 2009, respectively. Exploration expense for the three months ended September 30, 2010, resulted primarily from 3-D seismic data costs related to Cinco Terry and lease renewals in Ozona Northeast and Kentucky. Exploration expense for the 2009 period resulted primarily from the expiration of leases for approximately 2,300 net acres in Ozona Northeast and Cinco Terry.

General and administrative. Our general and administrative expenses (G&A) increased $975,000, or 43.6%, to $3.2 million ($1.28 per Mcfe) for the three months ended September 30, 2010, from $2.2 million ($1.12 per Mcfe) for the three months ended September 30, 2009. The increase in G&A was principally due to higher share-based compensation. Share-based compensation increased primarily as a result of a grant during the three months ended September 30, 2010, of performance-based, time-vesting restricted shares to executive officers. Following is a summary of G&A (in millions and per Mcfe):

	Three Months Ended September 30,						
	2010		2009		Change		% Change
	$MM	Mcfe	$MM	Mcfe	$MM	Mcfe	Mcfe
Salaries and benefits	$ 1.1	$ 0.43	$ 1.0	$ 0.48	$ 0.1	$ (0.05)	(10.4)%
Share-based compensation	1.1	0.45	0.4	0.21	0.7	0.24	114.3
Professional fees	0.4	0.18	0.3	0.15	0.1	0.03	20.0
Rent expense	0.1	0.05	0.1	0.06		(0.01)	(16.7)
Data processing	0.1	0.05	0.1	0.07		(0.02)	(28.6)
Other	0.4	0.12	0.3	0.15	0.1	(0.03)	(20.0)
Total	$ 3.2	$ 1.28	$ 2.2	$ 1.12	$ 1.0	$ 0.16	14.3%

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expense (DD&A) increased $237,000, or 4.2%, to $5.8 million for the three months ended September 30, 2010, from $5.6 million for the three months ended September 30, 2009. Our DD&A per Mcfe decreased by $0.47, or 16.8%, to $2.32 per Mcfe for the three months ended September 30, 2010, compared to $2.79 per Mcfe for the three months ended September 30, 2009. The decrease in DD&A per Mcfe was primarily attributable to an increase in estimated proved developed reserves at June 30, 2010, partially offset by higher production volumes and capital costs. Our estimated proved developed reserves at June 30, 2010, increased primarily due to the expected NGL recoveries in Ozona Northeast after the first quarter of 2011, higher commodity prices, well performance and results of development drilling in Cinco Terry.

Interest expense, net. Our interest expense, net, increased $164,000, or 36.4%, to $615,000 for the three months ended September 30, 2010, from $451,000 for the three months ended September 30, 2009. This increase was substantially the result of higher interest rates in the 2010 period and a higher average debt level in the 2010 period. Additionally, interest expense during the three months ended September 30, 2010, was higher due to an increase in amortization of $37,000 for deferred loan costs. The weighted average interest rate applicable to our outstanding borrowings during the three months ended September 30, 2010 and 2009, was 3.67% and 3.20%, respectively.

Income taxes. Our income taxes increased $2.5 million to $1.2 million for the three months ended September 30, 2010, from a benefit of $1.4 million for the three months ended September 30, 2009. The increase in income taxes was due to higher pretax income in the 2010 period. Our effective income tax rate for the three months ended September 30, 2010, was 35.9%, compared with 30.5% for the three months ended September 30, 2009. Total income tax expense for the three months end September 30, 2010, differed from amounts computed by applying the U.S. federal statutory tax rates to pretax income primarily due to state taxes and the impact of permanent differences between book and taxable income.

Nine Months Ended September 30, 2010, Compared to Nine Months Ended September 30, 2009

Oil and gas production. Production for the nine months ended September 30, 2010, totaled 6.7 Bcfe (24.6 MMcfe/d), compared to 6.8 Bcfe (25 MMcfe/d) produced in the prior year period, a decrease of 1.4%. Production for the nine months ended September 30, 2010, was 69% natural gas and 31% oil and NGLs, compared to 72% natural gas and 28% oil and NGLs in the prior year period. Production from tight gas reservoirs has a high initial rate of decline in the early life of the well. The natural decline of our tight gas fields and reduced drilling activity in 2009 caused a decline in our average daily production from the nine months ended September 30, 2009, to the nine months ended September 30, 2010. Production declined at a faster rate in our Cinco Terry field than Ozona Northeast, which we believe is typical given its earlier stage of development. Production declined at a slower rate in Ozona Northeast due to the later stage of development of the field.

Oil and gas sales. Oil and gas sales increased $12.5 million, or 43.5%, for the nine months ended September 30, 2010, to $41.3 million from $28.8 million for the nine months ended September 30, 2009. The increase in oil and gas sales principally resulted from an increase in realized oil and gas prices.

Commodity derivative activities. Our commodity derivative activity resulted in a realized gain of $3.6 million and $11.9 million for the nine months ended September 30, 2010, and 2009, respectively. Our average realized price, including the effect of commodity derivatives, was $6.68 per Mcfe for the nine months ended September 30, 2010, compared to $5.97 per Mcfe for the nine months ended September 30, 2009. Realized gains and losses on commodity derivatives are derived from the relative movement of gas prices in relation to the fixed notional pricing in our price swaps for the applicable periods. The unrealized gain on commodity derivatives was $2.9 million for the nine months ended September 30, 2010, compared to an unrealized loss of $8.6 million for the nine months ended September 30, 2009. As natural gas commodity prices increase, the fair value of the open portion of those positions decreases. As natural gas commodity prices decrease, the fair value of the open portion of those positions increases. Historically, we have not designated our derivative instruments as cash-flow hedges. We record our open derivative instruments at fair value on our consolidated balance sheets as either unrealized gains or losses on commodity derivatives. We record changes in such fair value in net income on our consolidated statements of operations under the caption entitled unrealized (loss) gain on commodity derivatives.

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Lease operating expenses. Our LOE for the nine months ended September 30, 2010, was $6 million ($0.90 per Mcfe), compared to $6 million ($0.88 per Mcfe) for the nine months ended September 30, 2009. The increase in LOE per Mcfe over the prior year period was primarily due to an increase in ad valorem taxes, pumping and supervision and water hauling and insurance, partially offset by a decrease in production and compression and gas treating over the prior year period. In addition, pumping and supervision costs increased due to our continued development of our fields, and compression and treating declined due to lower compressor rentals. The following is a summary of LOE (per Mcfe):

	Nine Months Ended September 30,			
	2010	2009	Change	% Change
Compression and gas treating	$ 0.25	$ 0.30	$ (0.05)	(16.7)%
Ad valorem taxes	0.20	0.16	0.04	25.0
Water hauling, insurance and other	0.18	0.16	0.02	12.5
Pumping and supervision	0.16	0.15	0.01	6.7
Well repairs and maintenance	0.10	0.10		
Workovers	0.01	0.01		
Total	$ 0.90	$ 0.88	$ 0.02	2.3%

Severance and production taxes. Our severance and production taxes increased $655,000, or 47.1%, for the nine months ended September 30, 2010, to $2 million from $1.4 million for the nine months ended September 30, 2009. The increase in severance and production taxes was primarily a function of the increase in oil and gas sales between the two periods. Severance and production taxes amounted to approximately 5.0% and 4.8% of oil and gas sales for the respective periods.

Exploration. We recorded $2.2 million and $534,000 of exploration expense for the nine months ended September 30, 2010 and 2009, respectively. Exploration expense for the nine months ended September 30, 2010, resulted primarily from 3-D seismic acquisition in Cinco Terry and lease renewals in Ozona Northeast, Cinco Terry and Kentucky. Exploration expense for the 2009 period resulted primarily from the expiration of leases for approximately 2,300 net acres in Ozona Northeast and Cinco Terry.

General and administrative. Our G&A increased $625,000, or 8.6%, to $7.9 million ($1.18 per Mcfe) for the nine months ended September 30, 2010, from $7.3 million ($1.07 per Mcfe) for the nine months ended September 30, 2009. The increase in G&A was principally due to higher share-based compensation, salaries and benefits and professional fees. Share-based compensation increased primarily as a result of a grant during the three months ended September 30, 2010, of performance-based, time-vesting restricted shares to executive officers. Following is a summary of G&A (in millions and per Mcfe):

	Nine Months Ended September 30,						
	2010		2009		Change		% Change
	$MM	Mcfe	$MM	Mcfe	$MM	Mcfe	Mcfe
Salaries and benefits	$ 3.3	$ 0.48	$ 3.0	$ 0.43	$ 0.3	$ 0.05	11.6%
Share-based compensation	2.0	0.30	1.5	0.22	0.5	0.08	36.4
Professional fees	1.0	0.14	0.9	0.14	0.1		
Data processing	0.4	0.05	0.5	0.08	(0.1)	(0.03)	(37.5)

Rent expense	0.3	0.05	0.4	0.05	(0.1)		
Other	0.9	0.16	1.0	0.15	(0.1)	0.01	6.7
Total	$ 7.9	$ 1.18	$ 7.3	$ 1.07	$ 0.6	$ 0.11	10.3%

Depletion, depreciation and amortization. Our DD&A decreased $2.1 million, or 11.1%, to $16.7 million for the nine months ended September 30, 2010, from $18.8 million for the nine months ended September 30, 2009. Our DD&A per Mcfe decreased by $0.27, or 9.8%, to $2.48 per Mcfe for the nine months ended September 30, 2010, compared to $2.75 per Mcfe for the nine months ended September 30, 2009. The decrease in DD&A was primarily attributable to an increase in estimated proved developed reserves at June 30, 2010, partially offset by higher capital costs over the prior year period. Our estimated proved developed reserves at June 30, 2010, increased primarily due to the expected NGL recoveries in Ozona Northeast after the first quarter of 2011, higher commodity prices and well performance and results of development drilling in Cinco Terry.

Interest expense, net. Our interest expense, net, increased $278,000, or 20.5%, to $1.6 million for the nine months ended September 30, 2010, from $1.4 million for the nine months ended September 30, 2009. This increase was substantially the result of an increase in amortization of $158,000 for deferred loan costs during the nine months ended September 30, 2010. The weighted average interest rate applicable to our outstanding borrowings during the nine months ended September 30, 2010 and 2009, was 3.34% and 3.23%, respectively.

Income taxes. Our income taxes increased $4.4 million to $4 million for the nine months ended September 30, 2010, from a benefit of $317,000 for the nine months ended September 30, 2009. The increase in income taxes was due to higher pretax income in the 2010 period, partially offset by higher taxes in the 2009 period from a change in our estimated income tax provision for the year ended December 31, 2008. Our effective income tax rate for the nine months ended September 30, 2010, was 36.0%, compared with 9.7% for the nine months ended September 30, 2009. The lower effective tax rate in the 2009 period primarily resulted from an increased impact of permanent differences from book and taxable income, partially offset by an increase in our estimated income taxes for the year ended December 31, 2008.

Liquidity and Capital Resources

We generally will rely on cash generated from operations, borrowings under our revolving credit facility and, to the extent that credit and capital market conditions will allow, future public equity and debt offerings to satisfy our liquidity needs. In October 2010, the lenders in our revolving credit facility increased the borrowing base under our credit agreement to $150 million from $115 million, based on mid-year 2010 proved reserves. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for temporary working capital needs and maintenance of our traditional Canyon Sands development drilling program. Future expansion of our drilling program or future acquisitions may require additional sources of equity or debt financing, which may not be available.

Our ability to fund future capital expenditures and to make acquisitions depends upon our future operating performance, borrowing availability under our revolving credit facility and the availability of equity and debt financing, which is affected by prevailing economic conditions in our industry and financial, business and other factors, some of which are beyond our control. We cannot predict whether additional liquidity from equity or debt financings beyond our revolving credit facility will be available on acceptable terms, or at all, in the foreseeable future.

Our cash flows from operating activities are affected by commodity prices, production, the effect of commodity derivatives, changes in working capital and the timing of cash receipts and payments. Prices for oil and gas are affected by national and international economic and political environments, national and global supply and demand for hydrocarbons, seasonal influences of weather and other factors beyond our control. Our working capital is significantly influenced by changes in commodity prices, and significant declines in commodity prices will cause a decrease in our production volumes and exploration and development expenditures. Our working capital also is influenced by our efforts to manage our long-term debt levels and related interest costs and, therefore, we maintain minimal cash balances. Our positive operating cash flow and available borrowing capabilities allow us to maintain a low or negative working capital position. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

The following table summarizes our sources and uses of funds for the periods noted (in thousands):

	Nine Months Ended September 30,	
	2010	**2009**
Cash flows provided by operating activities	$ 32,455	$ 22,930
Cash flows used in investing activities	(53,115)	(19,468)
Cash flows provided by (used in) financing activities	18,396	(6,848)
Effect of Canadian exchange rate	(4)	9
Net decrease in cash and cash equivalents	$ (2,268)	$ (3,377)

Operating Activities

During the nine months ended September 30, 2010, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling activities in Cinco Terry and Ozona Northeast, leasehold acquisitions in Project Pangea and the 3-D seismic program in Cinco Terry.

Cash provided by operating activities for the nine months ended September 30, 2010, was $32.5 million, compared to $22.9 million in the nine months ended September 30, 2009. Cash flows from operating activities increased $9.5 million from the same period in 2009 due primarily to a $12.5 million, or 43.5% increase, in oil and gas sales in the 2010 period. Cash flows provided by operating activities also were affected by an increase in cash flows used by working capital during the nine months ended September 30, 2010.

Investing Activities

The $53.1 million of cash flows used in investing activities during the nine months ended September 30, 2010, were primarily for the continued development of our Cinco Terry and Ozona Northeast fields, leasing approximately 28,994 net acres in the Permian Basin and acquiring 3-D seismic data across Cinco Terry. For the comparable 2009 period, the cash flows used in investing activities were primarily for drilling operations in Cinco Terry.

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Estimated Capital Expenditures for 2010

During the first nine months of 2010, capital expenditures totaled $52.4 million. We currently expect capital expenditures to total $31 million to $33 million during the three months ending December 31, 2010, and $83 million to $85 million for the full year ending December 31, 2010, including the acquisition of an additional 10% working interest in Cinco Terry for $21.5 million. The following table summarizes our capital expenditure during the first nine months of 2010 (in thousands).

	As of September 30, 2010
West Texas	
Ozona Northeast	$ 12,584
Cinco Terry	28,285
Inventory and other	911
Lease acquisition, geological and geophysical	10,605(a)
Total capital expenditures	$ 52,385

(a) Includes $9 million of lease acquisition costs and $1.6 million of 3-D seismic costs.

Our remaining capital expenditure budget for 2010 is subject to change depending upon a number of factors, including economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, gas and NGLs, the results of our development and exploration efforts, the availability of sufficient capital resources for drilling prospects, our financial results, lease extensions and renewals, the availability of new leases and our ability to obtain permits for drilling locations. We expect drilling rigs, drilling crews, steel tubulars and oilfield services, and particularly well completion services for hydraulic fracturing, to be in high demand in the Permian Basin during the remainder of 2010, and that the costs related to these services will continue to increase from 2009 levels.

Financing Activities

We borrowed $81.4 million and $55.9 million under our revolving credit facility during the nine months ended September 30, 2010, and 2009, respectively. We repaid $62.7 million and $62.5 million of the amounts borrowed under our revolving credit facility during the nine months ended September 30, 2010, and 2009, respectively.

Our current goal is to manage our borrowings to help us maintain financial flexibility and liquidity, and to avoid the problems associated with highly-leveraged companies with large interest costs and possible debt reductions restricting ongoing operations.

We believe that cash flows from operations and borrowings under our revolving credit facility will finance our temporary working capital needs and maintenance of our traditional Canyon Sands development drilling program. Future expansion of our drilling program or future acquisitions may require additional sources of financing beyond our operating cash flows and credit facility, including equity or additional debt financings. There is no guarantee that such financing will be available on acceptable terms or at all.

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Revolving Credit Facility

We have a $200 million revolving credit facility with a borrowing base set at $115 million at September 30, 2010. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

The maturity date under our revolving credit facility is July 31, 2012. Borrowings bear interest based on the agent bank s prime rate plus an applicable margin ranging from 1.25% to 2.25%, or the sum of the Eurodollar rate plus an applicable margin ranging from 2.25% to 3.25%. Margins vary based on the borrowings outstanding compared to the borrowing base. In addition, we pay an annual commitment of 0.50% of unused borrowings available under our revolving credit facility.

Effective February 1, 2010, we entered into a seventh amendment to our credit agreement, which replaced The Frost National Bank as the administrative agent under the credit agreement with JPMorgan Chase Bank, N.A., as successor agent.

Effective May 3, 2010, we entered into an eighth amendment to our credit agreement, which (i) extended the maturity date of the credit agreement by one year to July 31, 2012, (ii) increased the Company s commodity derivatives limit from 75% to 85% of annual projected production from proved developed producing oil and gas properties, (iii) reaffirmed the borrowing base and lenders aggregate commitment of $115 million and (iv) transferred Fortis Capital Corp. s interest in the credit agreement to BNP Paribas.

Effective October 21, 2010, we entered into a ninth amendment to our credit agreement, which increased the borrowing base and lenders aggregate commitment under the credit agreement to $150 million from $115 million.

We had outstanding borrowings of $51.1 million and $32.3 million under our revolving credit facility at September 30, 2010 and December 31, 2009, respectively. The weighted average interest rate applicable to our outstanding borrowings was 3.50% and 3.20% as of September 30, 2010, and December 31, 2009, respectively. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at September 30, 2010, which reduce amounts available for borrowing under our revolving credit facility.

Loans under our revolving credit facility are secured by first priority liens on substantially all of our West Texas assets and are guaranteed by our subsidiaries.

Covenants

Our credit agreement contains two principal financial covenants:

- a consolidated modified current ratio covenant that requires us to maintain a ratio of not less than 1.0 to 1.0 at all times. The consolidated modified current ratio is calculated by dividing Consolidated Current Assets (as defined in the credit agreement) by Consolidated Current Liabilities (as defined in the credit agreement). As defined more specifically in the credit agreement, the consolidated modified current ratio is calculated as current assets less current unrealized gains on commodity derivatives plus the available borrowing base at the respective balance sheet date, divided by current liabilities less current unrealized losses on commodity derivatives at the respective balance sheet date.

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a consolidated funded debt to consolidated EBITDAX ratio covenant that requires us to maintain a ratio of not more than 3.5 to 1.0 at the end of each fiscal quarter. The consolidated funded debt to consolidated EBITDAX ratio is calculated by dividing Consolidated Funded Debt (as defined in the credit agreement) by Consolidated EBITDAX (as defined in the credit agreement). As defined more specifically in the credit agreement, consolidated EBITDAX is calculated as net income (loss), plus (1) exploration expense, (2) depletion, depreciation and amortization expense, (3) share-based compensation expense, (4) unrealized loss on commodity derivatives, (5) interest expense, (6) income and franchise taxes, and (7) certain other noncash expenses, less (1) gains or losses from sales or dispositions of assets, (2) unrealized gain on commodity derivatives and (3) extraordinary or nonrecurring gains. For purposes of calculating this ratio, consolidated EBITDAX for a fiscal quarter is annualized pursuant to the credit agreement.

Our credit agreement also restricts cash dividends and other restricted payments, transactions with affiliates, incurrence of other debt, consolidations and mergers, the level of operating leases, assets sales, investments in other entities and liens on properties.

In addition, our credit agreement contains customary events of default that would permit our lenders to accelerate the debt under our credit agreement if not cured within applicable grace periods, including, among others, failure to make payments of principal or interest when due, materially incorrect representations and warranties, failure to make mandatory prepayments in the event of borrowing base deficiencies, breach of covenants, defaults upon other obligations in excess of $500,000, events of bankruptcy, the occurrence of one or more unstayed judgments in excess of $500,000 not covered by an acceptable policy of insurance, failure to pay any obligation in excess of $500,000 owed under any derivatives transaction or in any amount if the obligation under the derivatives transaction is secured by collateral under the credit agreement, any event of default by the Company occurs under any agreement entered into in connection with a derivatives transaction, liens securing the loans under the credit agreement cease to be in place, a Change in Control (as defined in the credit agreement) of the Company occurs, and dissolution of the Company.

At September 30, 2010, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

To date we have experienced no disruptions in our ability to access our revolving credit facility. However, our lenders have substantial ability to reduce our borrowing base on the basis of subjective factors, including the loan collateral value that each lender, in its discretion and using the methodology, assumptions and discount rates as such lender customarily uses in evaluating oil and gas properties, assigns to our properties.

We cannot predict with certainty the impact to us of any further disruption in the credit environment or guarantee that the lenders under our revolving credit facility will not decrease our borrowing base in the future. If our borrowing base was decreased below our total outstanding borrowings, resulting in a borrowing base deficiency, then we would be required under the credit agreement, within 15 days after notice from the agent bank, to (i) pledge additional collateral to cure the borrowing base deficiency, (ii) prepay the borrowing base deficiency in full or (iii) commit to repay the borrowing base deficiency in nine equal monthly installments, with the first installment being due within 30 days after receipt of notice from the agent bank. There is no guarantee that, in the event of such a borrowing base deficiency, we would be able to timely cure the deficiency.

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Contractual Obligations

There have been no material changes to our contractual obligations during the nine months ended September 30, 2010.

Off-Balance Sheet Arrangements

From time to time, we enter into off-balance sheet arrangements and transactions that can give rise to off-balance sheet obligations. As of September 30, 2010, the off-balance sheet arrangements and transactions that we have entered into include undrawn letters of credit, operating lease agreements and gas delivery commitments. We do not believe that these arrangements have or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in oil and gas prices, and other related factors. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for commodity derivative and investment purposes, not for trading purposes.

Commodity Price Risk

While realized commodity prices improved during the nine months ended September 30, 2010, compared to the prior year period, the outlook for natural gas remains uncertain. Even modest decreases in commodity prices can materially affect our revenues and cash flow. In addition, if commodity prices remain suppressed for a significant amount of time, we could be required under successful efforts accounting rules to perform a write down of our oil and gas properties.

We may enter into financial swaps to reduce the risk of commodity price fluctuations. We do not designate such instruments as cash flow hedges. Accordingly, we record open commodity derivative positions on our consolidated balance sheets at fair value and recognize changes in such fair values as income (expense) on our consolidated statements of operations as they occur.

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At September 30, 2010, we had the following commodity derivative positions outstanding:

Period	Volume (MMBtu) Monthly	Total	$/MMBtu Fixed
NYMEX Henry Hub			
Price swaps 2010	150,000	450,000	$ 5.85
Price swaps 2010	150,000	450,000	$ 6.40
Price swaps 2010	100,000	300,000	$ 6.36
Weighted average price ($/MMBtu)			$ 6.18
WAHA basis differential			
Basis swaps 2010	415,000	1,245,000	$ (0.71)
Basis swaps 2011	300,000	3,600,000	$ (0.53)

At September 30, 2010, and December 31, 2009, the fair value of our open derivative contracts was a net asset of approximately $1 million and a net liability of $1.9 million, respectively.

JPMorgan Chase Bank, National Association and KeyBank National Association are currently the only counterparties to our commodity derivatives positions. We are exposed to credit losses in the event of nonperformance by counterparties on our commodity derivatives positions. However, we do not anticipate nonperformance by the counterparties over the term of the commodity derivatives positions. JPMorgan is the administrative agent and a participant, and KeyBank is a participant, in our revolving credit facility and the collateral for the outstanding borrowings under our revolving credit facility is used as collateral for our commodity derivatives.

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of our commodity derivative contracts are recorded in net income as they occur and included in other income (expense) on our consolidated statements of operations. We estimate the fair values of swap contracts based on the present value of the difference in exchange-quoted forward price curves and contractual settlement prices multiplied by notional quantities. We use our internal valuations to determine the fair values of the contracts that are reflected on our consolidated balance sheets. Realized gains and losses are also included in other income (expense) on our consolidated statements of operations.

For the nine months ended September 30, 2010, we recorded an unrealized gain on commodity derivatives of $2.9 million, compared to an unrealized loss on commodity derivatives of $8.6 million for the nine months ended September 30, 2009, from the change in fair value of our commodity derivatives positions. A hypothetical 10% increase in commodity prices would have resulted in a $426,000 decrease in the fair value of our commodity derivative positions recorded on our balance sheet at September 30, 2010, and a corresponding decrease in the unrealized gain on commodity derivatives recorded on our consolidated statement of operations for the nine months ended September 30, 2010.

Item 4. Controls and Procedures.

Evaluation of Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in the reports we file under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Such controls include those designed to ensure that information required to be disclosed by us in the reports that we file or submit

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under the Exchange Act is accumulated and communicated to management, including the President and Chief Executive Officer (CEO) and Chief Financial Officer (CFO), as appropriate, to allow timely decisions regarding required disclosure.

Our management, with the participation of our CEO and CFO, has evaluated the effectiveness of our disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Exchange Act) as of September 30, 2010. Based on this evaluation, the CEO and CFO have concluded that, as of September 30, 2010, our disclosure controls and procedures were effective, in that they ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is (1) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (2) accumulated and communicated to our management, including our CEO and CFO, as appropriate to allow timely decisions regarding required disclosure.

Internal Control over Financial Reporting

There were no changes made in our internal control over financial reporting (as defined in Rule 13a-15(f) promulgated under the Exchange Act) during the three months ended September 30, 2010, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations Inherent in All Controls

Our management, including the CEO and CFO, recognizes that the disclosure controls and procedures and internal controls (discussed above) cannot prevent all errors or all attempts at fraud. Any controls system, no matter how well crafted and operated, can only provide reasonable, and not absolute, assurance of achieving the desired control objectives. Because of the inherent limitations in any control system, no evaluation or implementation of a control system can provide complete assurance that all control issues and all possible instances of fraud have been or will be detected.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings.

There have been no material developments in the legal proceedings described in Part I, Item 3. Legal Proceedings of our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 12, 2010.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the risks discussed in the following reports that we have filed with the SEC, which risks could materially affect our business, financial condition and results of operations: Annual Report on Form 10-K for the year ended December 31, 2009, under the headings Items 1. and 2. Business and Properties Markets and Customers; Competition; and Regulation, Item 1A. Risk Factors, and Item 7A. Quantitative and Qualitative Disclosures about Market Risk filed with the SEC on March 12, 2010; and Quarterly Report on Form 10-Q for the three months ended June 30, 2010, under the heading Item 1A. Risk Factors filed with the SEC on August 4, 2010.

Except as provided below, there have been no material changes to the risk factors discussed in our Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on March 12, 2010, and in our Quarterly Report on Form 10-Q for the three months ended June 30, 2010, filed with the SEC on August 4, 2010, which are accessible on the SEC s website at *www.sec.gov* and our website at *www.approachresources.com*.

The use of geoscientific, petropyhsical and engineering analyses and other technical or operating data to evaluate drilling prospects is uncertain and does not guarantee drilling success or recovery of economically producible reserves.

Our decisions to explore, develop and acquire prospects or properties targeting the Wolfcamp Shale, Clearfork and target zones in the Permian Basin and other areas depend on data obtained through geoscientific, petrophysical and engineering analyses, the results of which can be uncertain. Even when properly used and interpreted, data from whole cores, regional well log analyses and 3-D seismic only assist our technical team in identifying hydrocarbon indicators and subsurface structures and estimating hydrocarbons in place. They do not allow us to know conclusively the amount of hydrocarbons in place and if those hydrocarbons are producible economically. In addition, the use of advanced drilling and completion technologies for our Wolffork development, such as horizontal drilling and multi-stage fracture stimulations, requires greater expenditures than our traditional development drilling strategies. Our ability to commercially recover and produce the hydrocarbons that we believe are in place and attributable to the Wolfcamp Shale, Clearfork and other zones will depend on the effective use of advanced drilling and completion techniques, the scope of our drilling program (which will be directly affected by the availability of capital), drilling and production costs, availability of drilling and completion services and equipment, drilling results, lease expirations, regulatory approval and geological and mechanical factors affecting recovery rates. Our estimates of unproved reserves, estimated ultimate recoveries per well, hydrocarbons in place and resource potential may change significantly as development of our oil and gas assets provides additional data.

Climate change legislation or regulations restricting emissions of greenhouse gasses could result in increased operating costs and reduced demand for the oil and natural gas we produce.

On December 15, 2009, the U.S. Environmental Protection Agency, or EPA, published its findings that emissions of carbon dioxide, methane, and other greenhouse gases, or GHGs, present an endangerment to public heath and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth s atmosphere and other climate changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act pertaining to GHGs. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act construction and operating permit requirements for stationary sources, commencing when the motor vehicle standards take effect on January 2, 2011. On June 3, 2010, the EPA published its final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or PSD, and Title V permitting programs. This rule tailors these permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to best available control technology standards for GHG that have yet to be developed. With regards to the monitoring and reporting of GHGs, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. In addition, on April 10, 2010, the EPA published a proposed rule that would expand the existing GHG reporting rule to include onshore petroleum and natural gas production, processing, transmission storage and distribution facilities. If the proposed rule is finalized as proposed, reporting of GHG emissions from such facilities would be required on an annual basis, with reporting beginning in 2012 for emission occurring in 2011.

In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas we produce.

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

The following table provides information relating to our purchase of shares of our common stock during the three months ended September 30, 2010. The repurchases reflect shares withheld upon vesting of restricted stock under our 2007 Stock Incentive Plan to satisfy statutory minimum tax withholding obligations.

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
Month #1 July 1, 2010 July 31, 2010		$		
Month #2 August 1, 2010 August 31, 2010	317	8.22		
Month #3 September 1, 2010 September 30, 2010				
Total	317	$ 8.22		

Item 6. Exhibits.

See Index to Exhibits following the signature page of this report for a description of the exhibits furnished as part of this report.

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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.

	APPROACH RESOURCES INC.
Date: November 3, 2010	By: /s/ J. Ross Craft J. Ross Craft President and Chief Executive Officer (Principal Executive Officer)
Date: November 3, 2010	By: /s/ Steven P. Smart Steven P. Smart Executive Vice President and Chief Financial Officer (Principal Financial and Chief Accounting Officer)

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Index to Exhibits

Exhibit Number	*Description of Exhibit*
3.1	Restated Certificate of Incorporation of Approach Resources Inc. (filed as Exhibit 3.1 to the Company s Quarterly Report on Form 10-Q filed December 13, 2007, and incorporated herein by reference).
3.2	Restated Bylaws of Approach Resources Inc. (filed as Exhibit 3.2 to the Company s Quarterly Report on Form 10-Q filed December 13, 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 October 18, 2007 (File No. 333-144512) and incorporated herein by reference).
10.1	Ninth Amendment dated as of October 21, 2010, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as Agent and Lender, The Frost National Bank, BNP Paribas and KeyBank National Association, as Lenders, and Approach Oil & Gas Inc., Approach Oil & Gas (Canada) Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed October 26, 2010, and incorporated herein by reference).
*10.2	Form of Performance-Based, Time-Vesting Restricted Stock Award Agreement under Approach Resources Inc. 2007 Stock Incentive Plan.
*31.1	Certification by the President and Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*31.2	Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
*32.1	Certification by the President and Chief Executive Officer Pursuant to 18 U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification by the Chief Financial Officer Pursuant to U.S.C. Section 1350, as adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

Denotes management contract or compensatory plan or arrangement.