Approach Resources Inc
Form 10-Q
August 08, 2011

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 June 30, 2011

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).

þ 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 a 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 July 31, 2011, was 28,440,429.

TABLE OF CONTENTS

Table of Contents

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)

	June 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 831	$ 23,465
Accounts receivable:		
Joint interest owners	462	8,319
Oil, NGL and gas sales	8,973	6,044
Unrealized gain on commodity derivatives	1,278	862
Prepaid expenses and other current assets	474	322
Deferred income taxes current	1,799	2,318
Total current assets	13,817	41,330
PROPERTIES AND EQUIPMENT:		
Oil and gas properties, at cost, using the successful efforts method of accounting	632,698	474,917
Furniture, fixtures and equipment	1,507	1,077
	634,205	475,994
Less accumulated depletion, depreciation and amortization	(120,700)	(106,784)
Net properties and equipment	513,505	369,210
OTHER ASSETS	3,242	2,549
Total assets	$ 530,564	$ 413,089
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Advances from non-operators	$	$ 509
Accounts payable	17,696	11,426
Oil, NGL and gas sales payable	4,309	5,534
Accrued liabilities	14,320	10,686
Unrealized loss on commodity derivatives		1,085
Total current liabilities	36,325	29,240
NON-CURRENT LIABILITIES:		
Long-term debt	93,550	
Unrealized loss on commodity derivatives	289	871

Deferred income taxes	49,310	44,616
Asset retirement obligations	6,288	5,416
Total liabilities	185,762	80,143
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, 28,445,381 and 28,226,890 issued and outstanding, respectively	284	282
Additional paid-in capital	276,315	273,912
Retained earnings	68,439	58,986
Accumulated other comprehensive loss	(236)	(234)
Total stockholders equity	344,802	332,946
Total liabilities and stockholders equity	$ 530,564	$ 413,089

See accompanying notes to these consolidated financial statements.

1

Table of Contents

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

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
REVENUES:				
Oil, NGL and gas sales	$ 29,123	$ 13,155	$ 49,306	$ 26,375
EXPENSES:				
Lease operating	3,609	2,203	6,256	4,043
Severance and production taxes	1,701	610	2,804	1,304
Exploration	280	187	4,908	1,677
General and administrative	4,593	2,181	8,093	4,690
Depletion, depreciation and amortization	7,987	5,010	14,039	10,845
Total expenses	18,170	10,191	36,100	22,559
OPERATING INCOME	10,953	2,964	13,206	3,816
OTHER:				
Interest expense, net	(863)	(550)	(1,375)	(1,016)
Realized gain on commodity derivatives	66	1,768	262	1,998
Unrealized gain (loss) on commodity derivatives	2,231	(1,901)	2,082	3,194
Gain on sale of oil and gas properties	3		491	
INCOME BEFORE INCOME TAX PROVISION	12,390	2,281	14,666	7,992
INCOME TAX PROVISION	4,400	730	5,213	2,878
NET INCOME	$ 7,990	$ 1,551	$ 9,453	$ 5,114
EARNINGS PER SHARE:				
Basic	$ 0.28	$ 0.07	$ 0.33	$ 0.24
Diluted	$ 0.28	$ 0.07	$ 0.33	$ 0.24
WEIGHTED AVERAGE SHARES OUTSTANDING:				

Basic	28,458,270	21,059,413	28,376,414	21,027,982
Diluted	28,687,457	21,184,331	28,615,647	21,154,647

See accompanying notes to these consolidated financial statements.

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Net income	$7,990	$1,551	$9,543	$5,114
Other comprehensive income:				
Foreign currency translation, net of related income tax	(1)	5	(2)	
Total comprehensive income	$7,989	$1,556	$9,541	$5,114

See accompanying notes to these consolidated financial statements.

3

Table of Contents

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

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
OPERATING ACTIVITIES:		
Net income	$ 9,453	$ 5,114
Adjustments to reconcile net income to cash provided by operating activities:		
Depletion, depreciation and amortization	14,039	10,845
Unrealized gain on commodity derivatives	(2,082)	(3,194)
Gain on sale of oil and gas properties	(491)	
Exploration expense	4,908	1,677
Share-based compensation expense	2,548	996
Deferred income taxes	5,213	2,807
Changes in operating assets and liabilities:		
Accounts receivable	4,927	(3,846)
Prepaid expenses and other assets	29	235
Accounts payable	5,114	2,492
Oil, NGL and gas sales payable	(1,225)	1,368
Accrued liabilities	3,634	(162)
Cash provided by operating activities	46,067	18,332
INVESTING ACTIVITIES:		
Additions to oil and gas properties	(161,816)	(29,757)
Proceeds from gain on sale of oil and gas properties, net	363	
Additions to other property and equipment, net	(430)	(477)
Cash used in investing activities	(161,883)	(30,234)
FINANCING ACTIVITIES:		
Proceeds from issuance of common stock upon exercise of stock options	505	
Borrowings under credit facility, net of debt issuance costs	118,675	51,162
Repayment of amounts outstanding under credit facility	(26,000)	(41,650)
Cash provided by financing activities	93,180	9,512
CHANGE IN CASH AND CASH EQUIVALENTS	(22,636)	(2,390)
EFFECT OF FOREIGN CURRENCY TRANSLATION ON CASH AND CASH EQUIVALENTS	2	(2)
CASH AND CASH EQUIVALENTS, beginning of period	$ 23,465	$ 2,685

CASH AND CASH EQUIVALENTS, end of period	$	831	$	293
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid for interest	$	1,363	$	1,017

See accompanying notes to these consolidated financial statements.

Table of Contents

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
June 30, 2011

1. Summary of Significant Accounting Policies

Organization and Nature of Operations

Approach Resources Inc. (Approach, the Company, we, us or our) is an independent energy company engage the exploration, development, production and acquisition of oil and gas properties. We focus on finding and developing oil and natural gas reserves in oil shale and tight sands. Our properties are primarily located in the Permian Basin in West Texas. We also own interests in the East Texas Basin and the Chama Basin in Northern New Mexico.

During the six months ended June 30, 2011, we sold our working interest in Northeast British Columbia for net proceeds of $363,000. The gain on the sale of this interest was $491,000, and is included under Other on the consolidated statement of operations for the six months ended June 30, 2011. Our carrying value and associated plugging obligations related to Northeast British Columbia previously was written off as an impairment of unproved properties during the year ended December 31, 2009.

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, 2010, filed with the Securities and Exchange Commission on March 11, 2011.

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.

Table of Contents

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
June 30, 2011

2. Working Interest Acquisition

In February 2011, we acquired an additional 38% working interest in our Cinco Terry operating area from two non-operating partners for $76 million, subject to customary post-closing adjustments (the Working Interest Acquisition). We funded the Working Interest Acquisition with cash on hand and borrowings under our revolving credit facility.

The following table summarizes the preliminary purchase price paid and its allocation at June 30, 2011(in thousands).

Purchase price:	
Acquisition price	$ 76,000
Asset retirement obligations assumed	547
Post-closing purchase price adjustments	(6,366)
Total	$ 70,181
Allocation:	
Wells, equipment and related facilities	$ 50,979
Mineral interests in oil and gas properties	19,202
Total	$ 70,181

3. 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 table provides a reconciliation of the numerators and denominators of our basic and diluted earnings per share (dollars in thousands, except per-share amounts).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Income (numerator):				
Net income basic	$ 7,990	$ 1,551	$ 9,453	$ 5,114
Weighted average shares (denominator):				
Weighted average shares basic	28,458,270	21,059,413	28,376,414	21,027,982
Dilution effect of share-based compensation, treasury method	229,187	124,918	239,233	126,665
Weighted average shares diluted	28,687,457	21,184,331	28,615,647	21,154,647
Net income per share:				
Basic	$ 0.28	$ 0.07	$ 0.33	$ 0.24

Diluted	$	0.28	$	0.07	$	0.33	$	0.24

4. Revolving Credit Facility

At June 30, 2011, we had a $300 million revolving credit facility with a borrowing base set at $200 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil, NGL and gas reserves. We or the lenders can each request one additional borrowing base redetermination each calendar year.

Table of Contents

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
June 30, 2011

The maturity date under our revolving credit facility is July 31, 2014. Borrowings bear interest based on the agent bank s prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. 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 May 4, 2011, we entered into a tenth amendment (the Tenth Amendment) to our credit agreement, which (i) increased the borrowing base under the credit agreement to $200 million from $150 million, (ii) increased the lenders aggregate maximum commitment to $300 million from $200 million, (iii) extended the maturity date of the credit agreement by two years to July 31, 2014, (iv) increased the consolidated funded debt to consolidated EBITDAX ratio covenant to a ratio of not more than 4 to 1 from a ratio of not more than 3.5 to 1, (v) permitted the issuance of up to $200 million of senior unsecured debt; provided, that any such debt issuance will reduce the borrowing base by 25% of the principal amount of the issuance, and (vi) added a fifth bank, Royal Bank of Canada, to the lending group.

The Tenth Amendment also revised the applicable rate schedule to decrease the Eurodollar rate margin to a range of 1.75% to 2.75% from a range of 2.25% to 3.25% and decreased the base rate margin to a range of 0.75% to 1.75% from a range of 1.25% to 2.25%, each determined by the then-current percentage of the borrowing base that is drawn.

We had outstanding borrowings of $93.6 million under our revolving credit facility at June 30, 2011. We had no outstanding borrowings at December 31, 2010. The interest rate applicable to our revolving credit facility at June 30, 2011, was 2.71%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at June 30, 2011, 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 4.0 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

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
June 30, 2011

commodity derivatives, (5) interest expense, (6) income and franchise taxes and (7) certain other noncash expenses, less (x) gains or losses from sales or dispositions of assets, (y) unrealized gain on commodity derivatives and (z) 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 June 30, 2011, we were in compliance with all of our covenants and had not committed any acts of default under the credit agreement.

5. 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 are at least $2 million, 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 non-current assets on our balance sheet at June 30, 2011, and December 31, 2010. 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 contends that certain of the disputed operations were unnecessary, while other charges are improper because we failed to obtain EnCana s consent under the JOA prior to undertaking the operations.

We have entered into an 18-month contract for a dedicated, third-party fracture stimulation fleet, effective September 1, 2011. The contract requires a minimum commitment of $3 million per month for the contract term. The contract contains customary, early termination provisions for a monthly fee of less than the minimum monthly commitment in the event of a termination before the end of the contract term.

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

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
June 30, 2011

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.

6. Income Taxes

The effective income tax rate for the three and six months ended June 30, 2011, was 35.5%. Total income tax expense for the three and six months ended June 30, 2011, differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to state taxes and the impact of permanent differences between book and taxable income.

The effective income tax rate for the three and six months ended June 30, 2010, was 32% and 36%, respectively. Total income tax expense for the three and six months ended June 30, 2010, differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income.

7. Derivatives

The following table sets forth our commodity derivative volumes and prices as of June 30, 2011.

Period	Contract Type	Volume Transacted	Contract Price
Natural Gas			
2011	Swap	230,000 MMBtu/month	$4.86
June 2011 December 2011	Swap	200,000 MMBtu/month	$4.74
2012	Call	230,000 MMBtu/month	$6.00
Natural Gas Basis Differential			
2011	Swap	300,000 MMBtu/month	$(0.53)
Crude Oil			
May 2011 December 2011	Collar	1,000 Bbls/day	$100.00 - $127.00

The following table summarizes the fair value of our open commodity derivatives as of June 30, 2011, and December 31, 2010 (in thousands).

	Asset Derivatives			Liability Derivatives		
		Fair Value			Fair Value	
	Balance Sheet Location	June 30, 2011	December 31, 2010	Balance Sheet Location	June 30, 2011	December 31, 2010
Derivatives not designated as hedging instruments						
Commodity derivatives	Unrealized gain on commodity derivatives	$1,278	$862	Unrealized loss on commodity derivatives	$289	$1,956

9

Approach Resources Inc. and Subsidiaries
Notes to Consolidated Financial Statements (Unaudited)
June 30, 2011

The following table summarizes the change in the fair value of our commodity derivatives (in thousands).

	Income Statement Location	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Derivatives not designated as hedging instruments					
Commodity derivatives	Realized gain on commodity derivatives	$ 66	$ 1,768	$ 262	$ 1,998
	Unrealized gain (loss) on commodity derivatives	2,231	(1,901)	2,082	3,194
		$ 2,297	$ (133)	$ 2,344	$ 5,192

Unrealized gains and losses, at fair value, are included on our consolidated balance sheets as current or non-current 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 earnings 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 internally valued the option contracts using industry-standard option pricing models and observable market inputs. 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 June 30, 2011, 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 and collars, 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 June 30, 2011, 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 June 30, 2011, our Level 3 measurements were limited to our asset retirement obligation.

8. Share-Based Compensation

During the six months ended June 30, 2011, we made a grant of 204,000 restricted shares of common stock to our executive officers. The total fair market value of these shares on the grant date was approximately $6.5 million, which will be expensed over a service period of approximately four years, subject to certain performance measures. We recognized $1.2 million in share-based compensation expense related to this grant during the six months ended June 30, 2011.

Table of Contents

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

The following discussion is intended to assist in understanding our 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, 2010, filed with the Securities and Exchange Commission (SEC) on March 11, 2011. 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.

Cautionary Statement Regarding Forward-Looking 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, 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, anticipate, could, estim predict, project, potential or their negatives, other similar expressions or the statements that include those words, 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 or referred to 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, NGL and gas reserves;

- uncertainty of commodity prices in oil, gas and NGLs;

- overall United States and global economic and financial market conditions;

- domestic and foreign demand and supply for oil, gas, NGLs and the products derived from such hydrocarbons;

- disruption of credit and capital markets;

our financial position;

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 and completion, equipment, materials, 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;

development 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, 2010, filed with the SEC on March 11, 2011.

Table of Contents

Overview

Approach Resources Inc. (Approach, the Company, we, us or our) is an independent energy company engage the exploration, development, production and acquisition of oil and gas properties. We focus on oil and natural gas reserves in oil shale and tight sands. Our management and technical team has a proven track record of finding and developing reservoirs through advanced completion, fracturing and drilling techniques. Our core properties are primarily located in the Permian Basin in West Texas (Clearfork, Wolfcamp Shale, Canyon Sands, Strawn and Ellenburger). We also own interests in the East Texas Basin (Cotton Valley Sands and Cotton Valley Lime) and in the Chama Basin in Northern New Mexico (Mancos Shale). 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.

At June 30, 2011, we had estimated proved oil and gas reserves of 66.8 MMBoe. Our reserve base is 55% oil and NGLs, 45% natural gas and 50% proved developed. Over 97% of our proved reserves and production are located in the Permian Basin in Crockett and Schleicher Counties, Texas. Our acreage position in the Permian Basin totals approximately 140,400 net, primarily contiguous acres and is characterized by multiple oil and liquids-rich formations. Our 2011 drilling program includes operating three rigs to target the Wolffork, the Wolfcamp Shale and the Canyon Sands and deeper zones. We refer to our drilling program in the Permian Basin as Project Pangea and Pangea West.

Mid-Year 2011 Proved Oil and Gas Reserves

The following table sets forth summary information regarding our estimated proved reserves as of June 30, 2011. We determined the natural gas equivalent of oil and NGLs by using a conversion ratio of six Mcf of natural gas to one Bbl of oil or NGLs. The standardized measure of discounted future net cash flows (the Standardized Measure) for our proved reserves at June 30, 2011, was $328.7 million. The PV-10 of our estimated proved reserves at June 30, 2011, was $521.2 million.

	Proved Reserves			
Reserves Category	**Oil (MBbls)**	**NGLs (MBbls)**	**Natural Gas (MMcf)**	**Total (MBoe)**
PROVED				
Developed:				
Permian Basin	4,418	14,202	88,027	33,291
East Texas Basin			1,329	222
Total	4,418	14,202	89,356	33,513
Undeveloped:				
Permian Basin	5,709	12,588	79,544	31,554
East Texas Basin			10,688	1,781
Total	5,709	12,588	90,232	33,335
TOTAL PROVED at June 30, 2011	10,127	26,790	179,588	66,848

For the six months ended June 30, 2011, we engaged DeGolyer and MacNaughton, independent, third-party reserves engineers, to prepare independent estimates of our proved reserves. Estimates of the PV-10 of our proved reserves were prepared by the Company s internal reservoir engineers. Proved reserves volumes and PV-10 were prepared using $85.92 per Bbl of oil, $44.96 per Bbl of NGLs and $3.98 per Mcf of natural gas. All prices were adjusted for energy content, quality and basis differentials by field and were held constant through the lives of the properties.

Table of Contents

PV-10 is our estimate of the present value of future net revenues from proved oil and gas reserves after deducting estimated production and ad valorem taxes, future capital costs and operating expenses, but before deducting any estimates of future income taxes. PV-10 is a non-GAAP, financial measure and generally differs from the Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future cash flows. PV-10 should not be considered as an alternative to the Standardized Measure as computed under GAAP.

The following table shows our reconciliation of our PV-10 to the Standardized Measure. The estimated future net revenues are discounted at an annual rate of 10% to determine their present value.

	As of June 30, 2011 (in thousands)
PV-10	$ 521,160
Less income taxes:	
Undiscounted future income taxes	(470,075)
10% discount factor	277,579
Future discounted income taxes	(192,496)
Standardized measure of discounted future net cash flows	$ 328,664

We believe PV-10 to be an important measure for evaluating the relative significance of our oil and gas properties and that the presentation of the non-GAAP financial measure of PV-10 provides useful information to investors because it is widely used by professional analysts and sophisticated investors in evaluating oil and gas companies. Because there are many unique factors that can impact an individual company when estimating the amount of future income taxes to be paid, we believe the use of a pre-tax measure is valuable for evaluating our company. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis.

Second Quarter of 2011 Activity

During the second quarter of 2011, we drilled a total of 15 wells, completed 16 wells and recompleted three wells. Through June 30, 2011, we drilled 32 gross (28.2 net) wells, completed 32 gross (26.7 net) wells and recompleted four gross (four net) wells. At June 30, 2011, we had five wells waiting on completion. We currently have one horizontal rig and two vertical rigs running in Project Pangea. At June 30, 2011, we owned working interests in approximately 604 producing oil and gas wells.

Table of Contents

Results of Operations

The following table sets forth summary information regarding oil, NGL and gas revenues, production, average product prices and average production costs and expenses for the three and six months ended June 30, 2011 and 2010. We determined the barrel of oil equivalent using the ratio of six Mcf of natural gas to one barrel of oil equivalent, and one barrel of NGLs to one barrel of oil equivalent.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
Revenues (in thousands)				
Oil	$10,201	$ 3,940	$18,224	$ 7,495
NGLs	12,235	2,351	17,289	4,334
Gas	6,687	6,864	13,793	14,546
Total oil, NGL and gas sales	29,123	13,155	49,306	26,375
Realized gain on commodity derivatives	66	1,768	262	1,998
Total oil, NGL and gas sales including derivative impact	$29,189	$14,923	$49,568	$28,373
Production				
Oil (MBbls)	104	54	193	101
NGLs (MBbls)	236	58	341	104
Gas (MMcf)	1,608	1,558	3,260	2,982
Total (MBoe)	608	372	1,077	702
Total (MBoe/d)	6.7	4.1	6.0	3.9
Average prices				
Oil (per Bbl)	$ 97.89	$ 73.26	$ 94.57	$ 74.27
NGLs (per Bbl)	51.88	40.33	50.70	41.65
Gas (per Mcf)	4.16	4.41	4.23	4.88
Total (per Boe)	$ 47.90	$ 35.36	$ 45.78	$ 37.57
Realized gain on commodity derivatives (per Boe)	0.11	4.75	0.24	2.85
Total including derivative impact (per Boe)	$ 48.01	$ 40.11	$ 46.02	$ 40.42
Costs and expenses (per Boe)				
Lease operating (1)	$ 5.93	$ 5.93	$ 5.81	$ 5.76
Severance and production taxes	2.80	1.64	2.60	1.86
Exploration	0.46	0.50	4.56	2.39
General and administrative	7.55	5.87	7.51	6.68

Depletion, depreciation and amortization	13.14	13.47	13.04	15.45

(1) Lease operating expense per Boe includes ad valorem taxes.

Glossary

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

Boe. Barrel of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to on Bbl of oil equivalent.

MBbl. Thousand barrels of oil, condensate or NGLs.

MBoe. Thousand barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to one Bbl of oil equivalent.

Mcf. Thousand cubic feet of natural gas.

MMBoe. Million barrels of oil equivalent, determined using the ratio of six Mcf of gas to one Bbl of oil equivalent, and one Bbl of NGLs to one Bbl of oil equivalent.

MMcf. Million cubic feet of natural gas.

NGLs. Natural gas liquids.

/d. Per day when used with volumetric units or dollars.

Three Months Ended June 30, 2011, Compared to Three Months Ended June 30, 2010

Oil, NGL and gas sales. Oil, NGL and gas sales increased $16 million, or 121%, for the three months ended June 30, 2011, to $29.1 million, from $13.2 million for the three months ended June 30, 2010. Of the $16 million increase in oil, NGL and gas sales, approximately $14.4 million was attributable to an increase in production volumes and $1.6 million was attributable to an increase in oil and NGL prices. Subject to commodity prices, we expect our 2011 oil, NGL and gas sales to continue to increase over 2010 prior periods due to increased production volumes from our drilling program in the Permian Basin, the acquisition of additional working interest in northwest Project Pangea in first quarter 2011 (the Working Interest Acquisition) and realization of NGL revenues in Ozona Northeast resulting from a gas purchase and processing contract that provides for the sale of NGLs from the gas stream in the southeast portion of Project Pangea.

Our average realized prices for the three months ended June 30, 2011, before the effect of commodity derivatives, were $97.89 per Bbl of oil, $51.88 per Bbl of NGLs and $4.16 per Mcf of natural gas, compared to $73.26 per Bbl of oil, $40.33 per Bbl of NGLs and $4.41 per Mcf of natural gas, for the three months ended June 30, 2010. Our average realized price, including the effect of commodity derivatives, was $48.01 per Boe for the three months ended June 30, 2011, compared to $40.11 per Boe for the three months ended June 30, 2010. The regional index prices that we use to price our oil, NGL and gas sales sometimes reflect a discount to the relevant benchmark prices, such as New York Mercantile Exchange (NYMEX) and West Texas Intermediate (WTI). The difference between the benchmark price and the price we reference in our sales contacts is called a differential. We currently expect our 2011 oil price differential to increase over 2010 prior periods due to increased activity levels in the Permian Basin and demand for oil haulers in the region.

Oil, NGL and gas production. Production for the three months ended June 30, 2011, totaled 608 MBoe (6.7 MBoe/d), compared to 372 MBoe (4.1 MBoe/d) produced in the prior year period, an increase of 63%. Production for the three months ended June 30, 2011, was 56% oil and NGLs and 44% natural gas, compared to 30% oil and NGLs and 70% natural gas in the prior year period. The increase in production in the 2011 period is the result of our continued development of our Permian Basin properties, the Working Interest Acquisition and processing NGLs in the southeast portion of Project Pangea. We expect 2011 production to continue to increase over 2010 prior periods due to the Working Interest Acquisition, our expected drilling program in the Permian Basin and the processing of NGLs from the gas stream in the southeast portion of Project Pangea.

Commodity derivative activities. Our commodity derivative activity resulted in a realized gain of $66,000 and $1.8 million for the three months ended June 30, 2011, and 2010, respectively. Realized gains and losses on commodity derivatives are derived from the relative movement of commodity prices in relation to the fixed notional pricing in our price collars, options and swaps for the applicable periods. The unrealized gain on commodity derivatives was $2.2 million for the three months ended June 30, 2011, compared to an unrealized loss of $1.9 million for the three months ended June 30, 2010. As commodity prices increase, the fair value of the open portion of those positions decreases. As 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 gain (loss) on commodity derivatives.

Lease operating expenses. Our lease operating expenses (LOE) increased $1.4 million, or 64%, for the three months ended June 30, 2011, to $3.6 million ($5.93 per Boe) from $2.2 million ($5.93 per Boe) for the three months ended June 30, 2010. The increase in LOE for the three months ended June 30, 2011, was primarily attributable to the Working Interest Acquisition. In February 2011, we acquired the remaining 38% working interest in northwest Project Pangea, which increased our working interest to approximately 100%. We also experienced an increase in repair and maintenance expenses as well as generally higher service costs. Higher production volumes during the three months ended June 30, 2011, resulted in consistent LOE per Boe, compared to the three months ended June 30, 2010.

The following table summarizes LOE (per Boe).

	Three Months Ended June 30,			
	2011	**2010**	**Change**	**% Change**
Well repairs and maintenance	$ 1.39	$ 0.83	$ 0.56	67.5%
Ad valorem taxes	1.31	1.40	(0.09)	(6.4)
Compression and gas treating	1.31	1.70	(0.39)	(22.9)
Pumping and supervision	0.96	0.84	0.12	14.3
Water hauling, insurance and other	0.96	1.16	(0.20)	(17.2)
Total	$ 5.93	$ 5.93	$	%

Severance and production taxes. Our severance and production taxes increased $1.1 million, or 179%, for the three months ended June 30, 2011, to $1.7 million from $610,000 for the three months ended June 30, 2010. The increase in severance and production taxes was primarily the result of an increase in oil, NGL and gas sales between the two periods. Severance and production taxes were approximately 5.8% and 4.6% of oil, NGL and gas sales for the respective periods. For the remainder of 2011, we expect severance and production taxes as a percent of oil, NGL and gas sales will remain relatively consistent compared to the severance and production taxes for the six months ended June 30, 2011.

Exploration. We recorded $280,000 ($0.46 per Boe) and $187,000 ($0.50 per Boe) of exploration expense for the three months ended June 30, 2011 and 2010, respectively. Exploration expense for the three months ended June 30, 2011 and 2010, includes leases extensions and costs related to acquisition of 3-D seismic data.

General and administrative. Our general and administrative expenses (G&A) increased $2.4 million, or 111%, to $4.6 million ($7.55 per Boe) for the three months ended June 30, 2011, from $2.2 million ($5.87 per Boe) for the three months ended June 30, 2010. The increase in G&A was principally due to higher share-based compensation, salaries and benefits and professional fees. As discussed in Note 8 to our financial statements in this report, during the three months ended June 30, 2011, we recognized $1.2 million in share-based compensation expense related to a grant of 204,000 restricted shares of common stock to our executive officers. For 2011, we expect G&A to be higher, compared to 2010, as a result of higher share-based compensation and staffing increases during 2010.

Table of Contents

The following table summarizes G&A (in millions and per Boe).

	Three Months Ended June 30,						
	2011		2010		Change		
	$MM	Boe	$MM	Boe	$MM	Boe	% Change
Share-based compensation	$ 1.7	$ 2.82	$ 0.4	$ 1.12	$ 1.3	$ 1.70	151.8%
Salaries and benefits	1.6	2.66	1.1	2.97	0.5	(0.31)	(10.4)
Professional fees	0.4	0.57	0.2	0.61	0.2	(0.04)	(6.6)
Rent expense	0.2	0.29	0.1	0.32	0.1	(0.03)	(9.4)
Data processing	0.1	0.19	0.1	0.22		(0.03)	(13.6)
Other	0.6	1.02	0.3	0.63	0.3	0.39	61.9
Total	$ 4.6	$ 7.55	$ 2.2	$ 5.87	$ 2.4	$ 1.68	28.6%

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expense (DD&A) increased $3 million, or 59%, to $8 million for the three months ended June 30, 2011, from $5 million for the three months ended June 30, 2010. Our DD&A per Boe decreased by $0.33, or 2%, to $13.14 per Boe for the three months ended June 30, 2011, compared to $13.47 per Boe for the three months ended June 30, 2010. The decrease in DD&A per Boe was primarily attributable to an increase in estimated proved developed reserves, partially offset by an increase in production and capitalized costs over the prior year period.

Interest expense, net. Our interest expense, net, increased $313,000, or 57%, to $863,000 for the three months ended June 30, 2011, from $550,000 for the three months ended June 30, 2010. This increase was the result of higher average debt level in the 2011 period.

Income taxes. Our income taxes increased $3.7 million to $4.4 million for the three months ended June 30, 2011, from $730,000 for the three months ended June 30, 2010. The increase in income taxes was due to higher net income in the 2011 period. Our effective income tax rate for the three months ended June 30, 2011, was 35.5%, compared with 32% for the three months ended June 30, 2010.

Six Months Ended June 30, 2011, Compared to Six Months Ended June 30, 2010

Oil, NGL and gas sales. Oil, NGL and gas sales increased $22.9 million, or 87%, for the six months ended June 30, 2011, to $49.3 million, from $26.4 million for the six months ended June 30, 2010. Of the $22.9 million increase in oil, NGL and gas sales, approximately $21.9 million was attributable to an increase in production volumes and $1 million was attributable to an increase in oil and NGL prices. Subject to commodity prices, we expect our 2011 oil, NGL and gas sales to continue to increase over 2010 prior periods due to increased production volumes from our drilling program in the Permian Basin, the Working Interest Acquisition and realization of NGL revenues in Ozona Northeast resulting from a gas purchase and processing contract that provides for the sale of NGLs from the gas stream in the southeast portion of Project Pangea.

Our average realized prices for the six months ended June 30, 2011, before the effect of commodity derivatives, were $94.57 per Bbl of oil, $50.70 per Bbl of NGLs and $4.23 per Mcf of natural gas, compared to $74.27 per Bbl of oil, $41.65 per Bbl of NGLs and $4.88 per Mcf of natural gas, for the six months ended June 30, 2010. Our average realized price, including the effect of commodity derivatives, was $46.02 per Boe for the six months ended June 30, 2011, compared to $40.42 per Boe for the six months ended June 30, 2010. The regional index prices that we use to price our oil, NGL and gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX and WTI. The difference between the benchmark price and the price we reference in our sales contacts is called a differential. We currently expect our 2011 oil price differential to increase over 2010 prior periods due to increased activity levels in the Permian Basin and demand for oil haulers in the region.

Oil, NGL and gas production. Production for the six months ended June 30, 2011, totaled 1,077 MBoe (6 MBoe/d), compared to 702 MBoe (3.9 MBoe/d) produced in the prior year period, an increase of 53%. Production for the six months ended June 30, 2011, was 50% oil and NGLs and 50% natural gas, compared to 29% oil and NGLs and 71% natural gas in the prior year period. The increase in production in the 2011 period is the result of our continued development of our Permian Basin properties, the Working Interest Acquisition and processing NGLs in the southeast portion of Project Pangea. We expect production to continue to increase during 2011 due to the Working Interest Acquisition, our expected drilling program in the Permian Basin and the processing of NGLs from the gas stream in the southeast portion of Project Pangea.

Commodity derivative activities. Our commodity derivative activity resulted in a realized gain of $262,000 and $2 million for the six months ended June 30, 2011, and 2010, respectively. Realized gains and losses on commodity derivatives are derived from the relative movement of commodity prices in relation to the fixed notional pricing in our price collars, options and swaps for the applicable periods. The unrealized gain on commodity derivatives was $2.1 million and $3.2 million for the six months ended June 30, 2011 and 2010, respectively. As commodity prices increase, the fair value of the open portion of those positions decreases. As 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 gain (loss) on commodity derivatives.

Lease operating expenses. Our lease operating expenses (LOE) increased $2.2 million, or 55%, for the six months ended June 30, 2011, to $6.3 million ($5.81 per Boe) from $4 million ($5.76 per Boe) for the six months ended June 30, 2010. The increase in LOE for the six months ended June 30, 2011, was primarily attributable to the Working Interest Acquisition. In February 2011, we acquired the remaining 38% working interest in northwest Project Pangea, which increased our working interest to approximately 100%. We also experienced an increase in repair and maintenance expenses partially due to inclement winter weather in southwest Texas in the first quarter of 2011. Higher production volumes during the six months ended June 30, 2011, however, resulted in consistent LOE per Boe, compared to the six months ended June 30, 2010.

The following table summarizes LOE (per Boe).

	Six Months Ended June 30,			
	2011	**2010**	**Change**	**% Change**
Compression and gas treating	$ 1.25	$ 1.70	$ (0.45)	(26.5)%
Ad valorem taxes	1.23	1.26	(0.03)	(2.4)
Well repairs and maintenance	1.18	0.77	0.41	53.2
Water hauling, insurance and other	1.14	0.98	0.16	16.3
Pumping and supervision	1.01	1.05	(0.04)	(3.8)
Total	$ 5.81	$ 5.76	$ 0.05	0.9%

Severance and production taxes. Our severance and production taxes increased $1.5 million, or 115%, for the six months ended June 30, 2011, to $2.8 million from $1.3 million for the six months ended June 30, 2010. The increase in severance and production taxes was primarily a function of the increase in

Table of Contents

oil, NGL and gas sales between the two periods. Severance and production taxes were approximately 5.7% and 4.9% of oil, NGL and gas sales for the respective periods. For the remainder of 2011, we expect severance and production taxes as a percent of oil, NGL and gas sales will remain relatively consistent compared to the six months ended June 30, 2011.

Exploration. We recorded $4.9 million ($4.56 per Boe) and $1.7 million ($2.39 per Boe) of exploration expense for the six months ended June 30, 2011 and 2010, respectively. Exploration expense for the six months ended June 30, 2011, resulted primarily from the timing of lease extensions and expirations in the Permian Basin. During the three months ended March 31, 2011, we extended the acreage terms for an additional four years for approximately 9,200 acres in the northwest area of Project Pangea for $3.2 million, or approximately $350 per acre. Further, approximately 5,000 acres in the southeast area of Project Pangea expired during the three months ended March 31, 2011, resulting in approximately $1.2 million of exploration expense. We expect exploration expense to increase from 2010 levels during the remainder of 2011 due to lease extensions and planned 3-D seismic activity in Pangea West and Project Pangea. Exploration expense for the six months ended June 30, 2010, resulted primarily from our acquisition of 3-D seismic data across Cinco Terry.

General and administrative. Our general and administrative expenses (G&A) increased $3.4 million, or 73%, to $8.1 million ($7.51 per Boe) for the six months ended June 30, 2011, from $4.7 million ($6.68 per Boe) for the six months ended June 30, 2010. The increase in G&A was principally due to higher share-based compensation, salaries and benefits, professional fees and data processing. As discussed in Note 8 to our financial statements in this report, during the six months ended June 30, 2011, we recognized $1.2 million in share-based compensation expense related to a grant of 204,000 restricted shares of common stock to our executive officers. For 2011, we expect G&A to be higher, compared to 2010, as a result of higher share-based compensation and staffing increases during 2010.

The following table summarizes G&A (in millions and per Boe).

	Six Months Ended June 30,						
	2011		2010		Change		
	$MM	Boe	$MM	Boe	$MM	Boe	% Change
Salaries and benefits	$ 3.0	$ 2.81	$ 2.2	$ 3.14	$ 0.8	$ (0.33)	(10.5)%
Share-based compensation	2.6	2.37	1.0	1.42	1.6	0.95	66.9
Professional fees	0.9	0.78	0.5	0.76	0.4	0.02	2.6
Data processing	0.3	0.29	0.2	0.31	0.1	(0.02)	(6.5)
Rent expense	0.3	0.30	0.2	0.33	0.1	(0.03)	(9.1)
Other	1.0	0.96	0.6	0.72	0.4	0.24	33.3
Total	$ 8.1	$ 7.51	$ 4.7	$ 6.68	$ 3.4	$ 0.83	12.4%

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expense (DD&A) increased $3.2 million, or 29%, to $14 million for the six months ended June 30, 2011, from $10.8 million for the six months ended June 30, 2010. Our DD&A per Boe decreased by $2.41, or 16%, to $13.04 per Boe for the six months ended June 30, 2011, compared to $15.45 per Boe for the six months ended June 30, 2010. The decrease in DD&A per Boe was primarily attributable to an increase in estimated proved developed reserves, partially offset by an increase in production and capitalized costs over the prior year period.

Interest expense, net. Our interest expense, net, increased $359,000, or 35%, to $1.4 million for the six months ended June 30, 2011, from $1 million for the six months ended June 30, 2010. This increase was the result of higher average debt level in the 2011 period.

Table of Contents

Income taxes. Our income taxes increased $2.3 million, or 81%, to $5.2 million for the six months ended June 30, 2011, from $2.9 million for the six months ended June 30, 2010. The increase in income taxes was due to higher net income in the 2011 period. Our effective income tax rate for the six months ended June 30, 2011, was 35.5%, compared with 36.0% for the six months ended June 30, 2010.

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 or private equity and debt offerings to satisfy our liquidity needs. Our ability to fund planned capital expenditures and to make acquisitions depends upon our future operating performance, availability of borrowings under our revolving credit facility, and more broadly, on 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 operations are driven by commodity prices, production volumes and the effect of commodity derivatives. 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. Cash flows from operations are primarily used to fund exploration and development of our oil and gas properties.

We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, expansion of our current drilling program, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that financing will be available on acceptable terms or at all.

Liquidity

We define liquidity as funds available under our revolving credit facility plus cash and cash equivalents. At June 30, 2011, we had $93.6 million in long-term debt outstanding. We had no long-term debt outstanding at December 31, 2010. Our liquidity was $106.9 million and $173.1 million at June 30, 2011 and December 31, 2010, respectively.

The table below summarizes our liquidity position at June 30, 2011 and December 31, 2010 (dollars in thousands).

	Liquidity	
	June 30, 2011	**December 31, 2010**
Borrowing base	$ 200,000	$ 150,000
Cash and cash equivalents	831	23,465
Long-term debt	(93,550)	
Unused letters of credit	(350)	(350)
Liquidity	106,931	173,115

In February 2011, we acquired the remaining 38% working interest in Cinco Terry from two non-operating partners for $76 million, subject to customary post-closing adjustments. The Working Interest Acquisition was funded with borrowings under our revolving credit facility and cash on hand.

Working Capital

Our working capital is affected primarily by our cash and cash equivalents balance and our capital expenditure program. We had a working capital deficit of $22.5 million at June 30, 2011, compared to a working capital surplus of $12.1 million at December 31, 2010. The primary reason for the change in working capital was the use of cash to partially fund the Working Interest Acquisition. As a result of the Working Interest Acquisition and our planned capital expenditure budget for 2011, we expect to continue to operate and end the year 2011 with a working capital deficit. Historically, our working capital deficits have been substantially attributable to accrued liabilities and have been more than offset by liquidity available under our revolving credit facility. To the extent we operate or end the year 2011 with a working capital deficit, we expect such deficit to be more than offset by liquidity available under our revolving credit facility.

Cash Flows

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

	Six Months Ended June 30,	
	2011	**2010**
Cash flows provided by operating activities	$ 46,067	$ 18,332
Cash flows used in investing activities	(161,883)	(30,234)
Cash flows provided by financing activities	93,180	9,512
Effect of Canadian exchange rate	2	(2)
Net decrease in cash and cash equivalents	$ (22,634)	$ (2,392)

For the six months ended June 30, 2011, our primary sources of cash were from financing activities and operating activities. Approximately $93.2 million of cash from financing activities and $46.1 million of cash from operations were used to fund a portion of our drilling program.

Operating Activities

For the six months ended June 30, 2011, our cash flows from operations, borrowings under our revolving credit facility and available cash were used primarily for drilling activities and leasehold acquisitions in our operating area in the Permian Basin. Cash flows from operating activities increased by 151%, or $27.7 million, to $46.1 million from the 2010 period primarily due to a 87% increase in oil, NGL and gas sales in the 2011 period.

Investing Activities

Cash flows used in investing activities increased by $131.6 million for six months ended June 30, 2011, compared to the 2010 period, which primarily reflects the acquisition of the remaining 38% working interest in Cinco Terry for $70.2 million, net of purchase price adjustments, and expenditures for drilling and lease acquisitions in our core operating area in the Permian Basin.

Table of Contents

Financing Activities

Proceeds from borrowings, net of debt issuance costs, were $118.7 million and $51.2 million, respectively, under our revolving credit facility during the six months ended June 30, 2011 and 2010, respectively. We repaid a total of $26 million and $41.7 million, respectively, of amounts outstanding under our revolving credit facility during the six months ended June 30, 2011 and 2010, respectively. In addition, in the six months ended June 30, 2011, we realized proceeds of $505,000 from the exercise of stock options.

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.

2011 Capital Expenditures

Total capital expenditures are expected to be approximately $220 million, with approximately $130 million allocated to drilling and recompletion projects in the Permian Basin and approximately $90 million allocated to the acquisition of the remaining 38% working interest in northwest Project Pangea, lease extensions, renewals and acquisitions in the Permian Basin and the acquisition of 3-D seismic in the Permian Basin.

Our 2011 capital budget is subject to change depending upon a number of factors, including additional data on our Wolffork oil shale resource play, results of Wolfcamp Shale and Wolffork drilling and recompletions, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil, gas and NGLs, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Revolving Credit Facility

At June 30, 2011, we had a $300 million revolving credit facility with a borrowing base set at $200 million. The borrowing base is redetermined semi-annually on or before each April 1 and October 1 based on our oil, NGL 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, 2014. Borrowings bear interest based on the agent bank s prime rate plus an applicable margin ranging from 0.75% to 1.75%, or the sum of the Eurodollar rate plus an applicable margin ranging from 1.75% to 2.75%. 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 May 4, 2011, we entered into a tenth amendment (the Tenth Amendment) to our credit agreement, which (i) increased the borrowing base under the credit agreement to $200 million from $150 million, (ii) increased the lenders aggregate maximum commitment to $300 million from $200 million, (iii) extended the maturity date of the credit agreement by two years to July 31, 2014, (iv) increased the consolidated funded debt to consolidated EBITDAX ratio covenant to a ratio of not more than 4 to 1 from a ratio of not more than 3.5 to 1, (v) permitted the issuance of up to $200 million of senior unsecured debt; provided, that any such debt issuance will reduce the borrowing base by 25% of the principal amount of the issuance, and (vi) added a fifth bank, Royal Bank of Canada, to the lending group.

Table of Contents

The Tenth Amendment also revised the applicable rate schedule to decrease the Eurodollar rate margin to a range of 1.75% to 2.75% from a range of 2.25% to 3.25% and decreased the base rate margin to a range of 0.75% to 1.75% from a range of 1.25% to 2.25%, each determined by the then-current percentage of the borrowing base that is drawn.

We had outstanding borrowings of $93.6 million under our revolving credit facility at June 30, 2011. We had no outstanding borrowings at December 31, 2010. The interest rate applicable to our revolving credit facility at June 30, 2011, was 2.71%. We also had outstanding unused letters of credit under our revolving credit facility totaling $350,000 at June 30, 2011, 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 4.0 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 (x) gains or losses from sales or dispositions of assets, (y) unrealized gain on commodity derivatives and (z) 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 June 30, 2011, 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.

Contractual Obligations

Our contractual obligations include long-term debt, daywork drilling contracts, operating lease obligations, asset retirement obligations and employment agreements with our executive officers. Since December 31, 2010, there have been no material changes to our contractual obligations other than, as discussed in Note 4 to our financial statements in this report, an increase in outstanding borrowings under our credit agreement to $93.6 million at June 30, 2011, and an extension of the credit facility loan maturity to July 2014. In addition, as discussed in Note 5 to our financial statements in this report, we have entered into an 18-month contract for a dedicated, third-party fracture stimulation fleet, effective September 1, 2011. The contract requires a minimum commitment of $3 million per month for the contract term. The contract contains customary, early termination provisions for a monthly fee of less than the minimum monthly commitment in the event of a termination before the end of the contract term.

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 June 30, 2011, 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.

General Trends and Outlook

Our financial results depend upon many factors, particularly the price of oil, NGLs and gas. Commodity prices are affected by changes in market demand, which is impacted by overall economic activity, weather, pipeline capacity constraints, estimates of inventory storage levels, gas price differentials and other factors. As a result, we cannot accurately predict future oil, NGL and gas prices, and therefore, we cannot determine what effect increases or decreases will have on our capital program, production volumes and future revenues. A substantial or extended decline in oil, NGL and gas prices could have a material adverse effect on our business, financial condition, results of operations, quantities of oil and gas reserves that may be economically produced and liquidity that may be accessed through our borrowing base under our revolving credit facility and through capital markets.

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 our efforts on increasing oil, NGL and gas reserves and production while controlling costs at a level that is appropriate for 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 attempt to overcome this natural decline by drilling to develop and identify additional reserves, farm-ins or other joint drilling ventures, and by acquisitions. However, during times of severe price declines, we may from time to time reduce current capital expenditures and curtail drilling operations in order to preserve liquidity. 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.

We also face the challenge of financing exploration, development and future acquisitions. We believe we have adequate liquidity from cash generated from operations and unused borrowing capacity under our revolving credit facility for current working capital needs and maintenance of our current drilling program. However, we may determine to access the public or private equity or debt markets for future development of reserves, acquisitions, expansion of our current drilling program, additional working capital or other liquidity needs, if such financing is available on acceptable terms. We cannot guarantee that such financing will be available on acceptable terms or at all.

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

Given the current economic outlook, we expect commodity prices to remain volatile. 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 enter into financial swaps, options and collars 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 other income (expense) on our consolidated statements of operations as they occur.

The following table sets forth our commodity derivative volumes and prices as of June 30, 2011.

Period	Contract Type	Volume Transacted	Contract Price
Natural Gas			
2011	Swap	230,000 MMBtu/month	$4.86
June 2011 December 2011	Swap	200,000 MMBtu/month	$4.74
2012	Call	230,000 MMBtu/month	$6.00
Natural Gas Basis Differential			
2011	Swap	300,000 MMBtu/month	$(0.53)
Crude Oil			
May 2011 December 2011	Collar	1,000 Bbls/day	$100.00 - $127.00

At June 30, 2011, the fair value of our open derivative contracts was a net asset of approximately $1 million. At December 31, 2010, the fair value of our open derivative contracts was a net liability of approximately $1.1 million.

JPMorgan Chase Bank, National Association (JPMorgan) and KeyBank National Association (KeyBank) 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 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 six months ended June 30, 2011 and 2010, we recorded an unrealized gain on commodity derivatives of $2.1 million and $3.2 million, respectively, from the change in fair value of our commodity derivatives positions. A hypothetical 10% increase in commodity prices would have resulted in a $2.2 million decrease in the fair value of our commodity derivative positions recorded on our balance sheet at June 30, 2011, and a corresponding decrease in the unrealized gain on commodity derivatives recorded on our consolidated statement of operations for the six months ended June 30, 2011.

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 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 June 30, 2011. Based on this evaluation, the CEO and CFO have concluded that, as of June 30, 2011, 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 June 30, 2011, 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.

Table of Contents

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, 2010, filed with the SEC on March 11, 2011.

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 report 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, 2010, filed with the SEC on March 11, 2011, under the headings Item 1. Business Markets and Customers; Competition; and Regulation, Item 1A. Risk Factors, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations General Trends and Outlook and Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

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, 2010, filed with the SEC on March 11, 2011, which is accessible on the SEC s website at *www.sec.gov* and our website at *www.approachresources.com*.

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 June 30, 2011. 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				
April 1, 2011 April 30, 2011		$		
Month #2				
May 1, 2011 May 31, 2011	6,595	24.71		
Month #3				
June 1, 2011 June 30, 2011	15,452	26.05		
Total	22,047	$ 25.65		

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.

Table of Contents

SIGNATURES

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

	APPROACH RESOURCES INC.
Date: August 8, 2011	By: /s/ J. Ross Craft J. Ross Craft President and Chief Executive Officer (Principal Executive Officer)
Date: August 8, 2011	By: /s/ Steven P. Smart Steven P. Smart Executive Vice President and Chief Financial Officer (Principal Financial and Chief Accounting Officer)

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	Amendment No. 10 dated as of May 4, 2011, to Credit Agreement dated as of January 18, 2008, among Approach Resources Inc., as Borrower, JPMorgan Chase Bank, N.A., as administrative agent and lender, BNP Paribas, KeyBank National Association, The Frost National Bank and Royal Bank of Canada, as lenders, and Approach Oil & Gas Inc. and Approach Resources I, LP, as guarantors (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed May 4, 2011, and incorporated herein by reference).
*23.1	Consent of DeGolyer and MacNaughton.
*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.
*99.1	Report of DeGolyer and MacNaughton.
**101.INS	XBRL Instance Document.
**101.SCH	XBRL Taxonomy Extension Schema.
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

* Filed herewith.

** Furnished herewith.