ENERGY PARTNERS LTD
Form 10-Q
November 03, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2011

OR

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

Commission file number: 001-16179

ENERGY PARTNERS, LTD.

(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State or Other Jurisdiction of** **Incorporation or Organization)**	**72-1409562** **(I.R.S. Employer** **Identification Number)**
201 St. Charles Ave., Suite 3400 New Orleans, Louisiana **(Address of principal executive offices)**	**70170** **(Zip code)**

(504) 569-1875

(Registrant s telephone number, including area code)

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

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

Large accelerated filer	¨	Accelerated filer	x
Non-accelerated filer	¨ (Do not check if a smaller reporting company).	Smaller reporting company	¨

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

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes x No ¨

As of November 1, 2011, there were 39,647,907 shares of the Registrant s Common Stock, par value $0.001 per share, outstanding.

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PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS.

ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

(In thousands, except share data)	**September 30, 2011**	**December 31, 2010**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 87,268	$ 33,553
Trade accounts receivable net	27,264	21,443
Receivables from insurance	805	2,088
Fair value of commodity derivative instruments	12,588	186
Deferred tax assets		2,693
Prepaid expenses	8,630	3,303
Total current assets	136,555	63,266
Property and equipment, under the successful efforts method of accounting for oil and natural gas properties	1,005,229	719,147
Less accumulated depreciation, depletion and amortization	(260,326)	(168,055)
Net property and equipment	744,903	551,092
Restricted cash	6,022	8,489
Fair value of commodity derivative instruments	6,400	
Other assets	2,675	1,814
Deferred financing costs net of accumulated amortization of $730 and $1,656 at September 30, 2011 and December 31, 2010, respectively	5,603	2,245
	$ 902,158	$ 626,906
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 18,225	$ 18,358
Accrued expenses	47,679	28,394
Asset retirement obligations	23,676	16,902
Fair value of commodity derivative instruments		12,320
Deferred tax liabilities	6,537	
Total current liabilities	96,117	75,974
Long-term debt	204,216	
Asset retirement obligations	64,302	54,681
Deferred tax liabilities	33,339	22,469
Other	663	666
Commitments and contingencies (Note 9)		
	398,637	153,790
Stockholders equity:		

Preferred stock, $0.001 par value per share. Authorized 1,000,000 shares; no shares issued and outstanding at September 30, 2011 and December 31, 2010		
Common stock, $0.001 par value per share. Authorized 75,000,000 shares; shares issued 40,244,252 and 40,091,664 at September 30, 2011 and December 31, 2010, respectively; shares outstanding 39,777,907 and 40,091,664 at September 30, 2011 and December 31, 2010, respectively	40	40
Additional paid-in capital	504,540	502,556
Retained Earnings (Accumulated deficit)	4,472	(29,480)
Treasury stock, at cost, 466,345 shares at September 30, 2011	(5,531)	
Total stockholders equity	503,521	473,116
	$ 902,158	$ 626,906

See accompanying notes to condensed consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(UNAUDITED)

(In thousands, except per share data)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Revenue:				
Oil and natural gas	$ 84,853	$ 56,237	$ 244,866	$ 185,083
Other	31	34	97	104
	84,884	56,271	244,963	185,187
Costs and expenses:				
Lease operating	19,266	12,857	52,505	40,974
Transportation	119	251	490	1,053
Exploration expenditures and dry hole costs	973	1,291	2,343	3,928
Impairments	5,523	12,366	19,197	24,020
Depreciation, depletion and amortization	26,496	25,323	73,081	81,284
Accretion of liability for asset retirement obligations	4,793	3,200	12,172	9,644
General and administrative	4,461	4,807	14,544	13,870
Taxes, other than on earnings	3,493	3,106	10,506	7,419
Other	4,108	256	6,140	747
Total costs and expenses	69,232	63,457	190,978	182,939
Income (loss) from operations	15,652	(7,186)	53,985	2,248
Other income (expense):				
Interest income	37	8	64	105
Interest expense	(5,036)	(726)	(12,480)	(8,873)
Gain (loss) on derivative instruments	26,571	(3,918)	14,877	1,115
Loss on early extinguishment of debt			(2,377)	(5,627)
	21,572	(4,636)	84	(13,280)
Income (loss) before income taxes	37,224	(11,822)	54,069	(11,032)
Deferred income tax benefit (expense)	(13,766)	3,976	(20,117)	3,692
Net income (loss)	23,458	(7,846)	33,952	(7,340)
Basic earnings (loss) per share	$ 0.59	$ (0.20)	$ 0.85	$ (0.18)
Diluted earnings (loss) per share	$ 0.58	$ (0.20)	$ 0.84	$ (0.18)
Weighted average common shares used in computing earnings (loss) per share:				
Basic	40,093	40,078	40,094	40,059
Effect of dilutive stock options and restricted shares	82		107	
Diluted	40,175	40,078	40,201	40,059

See accompanying notes to condensed consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

(In thousands)	**Nine Months Ended September 30, 2011**	**2010**
Cash flows from operating activities:		
Net income (loss)	$ 33,952	$ (7,340)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	73,081	81,284
Accretion of liability for asset retirement obligations	12,172	9,644
Unrealized gain on derivative contracts	(31,122)	(8,298)
Non-cash compensation	1,833	995
Deferred income taxes	20,117	(3,692)
Repayment of PIK Notes issued for payment of in-kind interest		(3,395)
Exploration expenditures	147	2,813
Impairments	19,197	24,020
Amortization of deferred financing costs and discount on debt	1,152	748
Loss on early extinguishment of debt	2,377	
Other	4,611	853
Changes in operating assets and liabilities:		
Trade accounts receivable	(6,430)	4,587
Other receivables	1,283	3,376
Prepaid expenses	(5,207)	(1,533)
Other assets	(862)	342
Accounts payable and accrued expenses	5,563	3,661
Other liabilities	(25,929)	(11,073)
Net cash provided by operating activities	105,935	96,992
Cash flows provided by (used in) investing activities:		
Decrease in restricted cash	2,467	12,166
Property acquisitions	(196,533)	(623)
Exploration and development expenditures	(49,246)	(43,032)
Other property and equipment additions	(833)	
Net cash used in investing activities	(244,145)	(31,489)
Cash flows provided by (used in) financing activities:		
Proceeds from indebtedness	203,794	20,394
Repayments of indebtedness		(82,382)
Deferred financing costs	(6,465)	(33)
Purchase of shares into treasury	(5,523)	
Exercise of stock options	119	
Net cash provided by (used in) financing activities	191,925	(62,021)
Net increase in cash and cash equivalents	53,715	3,482
Cash and cash equivalents at beginning of period	33,553	26,745
Cash and cash equivalents at end of period	$ 87,268	$ 30,227

SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:	
Debt incurred to pay deferred financing costs	737

See accompanying notes to condensed consolidated financial statements.

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ENERGY PARTNERS, LTD. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

(1) BASIS OF PRESENTATION

Energy Partners, Ltd. (we, our, us, or the Company) was incorporated as a Delaware corporation on January 29, 1998. We are an independent o and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana.

The financial information as of September 30, 2011 and for the three- and nine-month periods ended September 30, 2011 and September 30, 2010 has not been audited. However, in the opinion of management, all adjustments (which include only normal, recurring adjustments) necessary to present fairly the financial position and results of operations for the periods presented have been included therein. Certain information and footnote disclosures normally in financial statements prepared in accordance with generally accepted accounting principles have been condensed or omitted pursuant to rules and regulations of the Securities and Exchange Commission (the SEC). The condensed consolidated balance sheet at December 31, 2010 has been derived from the audited financial statements at that date. Certain reclassifications have been made to the prior period financial statements in order to conform to the classification adopted for reporting in the current period. These financial statements and footnotes should be read in conjunction with the financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2010, as amended (the 2010 Annual Report). The results of operations and cash flows for the first nine months of the year are not necessarily indicative of the results of operations which might be expected for the entire year.

(2) ACQUISITIONS

On February 14, 2011, we acquired an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the ASOP Properties) from Anglo-Suisse Offshore Partners, LLC (ASOP) for $200.7 million in cash, subject to purchase price adjustments to reflect an economic effective date of January 1, 2011 (the ASOP Acquisition). As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. The primary factors considered by management in acquiring the ASOP Properties include the belief that the ASOP Acquisition provides an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus on oil-weighted assets in our core area of expertise in the Gulf of Mexico shelf.

The ASOP Acquisition was financed with the proceeds from the sale of $210 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes), which were offered in a private placement only to qualified institutional buyers under Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), or to persons outside of the United States in compliance with Regulation S promulgated under the Securities Act. After deducting the initial purchasers discount and offering expenses, we realized net proceeds of approximately $202 million. See Note 6, Indebtedness for more information regarding our 8.25% Notes.

We have accounted for the ASOP Acquisition using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the ASOP Properties as of the February 14, 2011 acquisition date. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the ASOP Properties based on the implied valuations of other similar operations; (ii) comparable asset transaction analysis, which estimates the value of the acquired operations based upon publicly announced transactions of assets with similar characteristics; (iii) comparable merger transaction analysis, which, much like comparable asset transaction analysis, estimates the value of operations based upon publicly announced transactions with similar characteristics, except that merger analysis analyzes public to public merger transactions rather than solely asset transactions; and (iv) discounted cash flow analysis, which estimates the value of the ASOP Properties by determining the present value of estimated future cash flows. The fair value is based on subjective estimates and assumptions, which are inherently subject to significant uncertainties which are beyond our control. These assumptions represent Level 3 inputs, as further discussed in Note 8, Fair Value Measurements.

The following allocation of the purchase price as of February 14, 2011 is preliminary and includes significant estimates. This preliminary allocation is based on information that was available to management at the time these consolidated financial statements were prepared and is subject to revision as management finalizes key assumptions in the fair value models, primarily finalization of the oil and natural gas reserve analysis. Accordingly, the allocation may change as additional information becomes available and is assessed by management, and the impact of such changes may be material.

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The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects management s current estimate of adjustments to purchase price provided for by the purchase and sale agreement of approximately $4.2 million to reflect an economic effective date of January 1, 2011.

(In thousands)	February 14, 2011
Oil and natural gas properties	$ 220,743
Asset retirement obligations	(24,225)
Net assets acquired	$ 196,518

Revenues attributable to the ASOP Properties for the three and nine months ended September 30, 2011 were $33.6 million and $85.6 million, respectively. Lease operating expenses attributable to the ASOP Properties for the three and nine months ended September 30, 2011 were $5.7 million and $12.0 million, respectively. We have determined that the presentation of net income attributable to the ASOP Properties is impracticable due to the integration of the related operations upon acquisition. We incurred approximately $0.5 million in fees related to the acquisition, which were included in general and administrative expenses in the accompanying consolidated statement of operations for the nine months ended September 30, 2011.

The following supplemental pro forma information presents consolidated results of operations as if the ASOP Acquisition had occurred on January 1, 2010. This supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations and b) the statements of revenues and direct operating expenses for the ASOP Properties, which were derived from ASOP s historical accounting records. This information does not purport to be indicative of results of operations that would have occurred had the acquisition occurred on January 1, 2010, nor is such information indicative of any expected future results of operations.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	Actual 2011	Pro Forma 2010	Pro Forma 2011	Pro Forma 2010
	(in thousands, except per share data)			
Revenue	$ 84,884	$ 79,466	$ 257,721	$ 252,098
Net income (loss)	$ 23,458	$ (4,263)	$ 35,871	$ 3,030
Basic earnings (loss) per share	$ 0.59	$ (0.11)	$ 0.89	$ 0.08
Diluted earnings (loss) per share	$ 0.58	$ (0.11)	$ 0.89	$ 0.08

Subsequent Event

On October 28, 2011, we entered into a purchase and sale agreement with Stone Energy Offshore, L.L.C. (Seller) relating to the purchase (the Main Pass Acquisition) of certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the Main Pass Interests) for $80.0 million in cash, subject to customary adjustments to reflect the economic effective date of November 1, 2011. The Main Pass Interests currently produce approximately 900 barrels of oil equivalent per day, approximately 96% of which is oil. The Main Pass Interests consist of additional interests in the Main Pass 296/311 complex that was included in the assets we purchased from ASOP in February 2011, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. We estimate that the proved reserves as of the November 1, 2011 economic effective date totaled approximately 2.6 Mmboe, all of which were proved developed reserves and approximately 96% of which were oil reserves. The estimated asset retirement obligation to be assumed and recorded on our balance sheet as a result of the Main Pass Acquisition is expected to total approximately $4 million. The consummation of the Main Pass Acquisition is subject to customary closing conditions and is expected to close in November 2011. We intend to fund the Main Pass Acquisition with cash on hand.

The Main Pass Interests are not operated by Seller, and the other working interest owner and current operator of the Main Pass 296/311 complex has a preferential right under the applicable operating agreements to purchase the Main Pass Interests as a result of the Main Pass Acquisition. However, even if the operator exercises its preferential purchase right, the applicable operating agreements limit the amount that the operator can acquire by exercising the preferential right. In that case, the Main Pass Acquisition would still be completed, but, depending upon the various scenarios of the other working interest owner exercising at least one or more of the preferential rights, we would generally acquire 50% of the Main Pass Interests (with certain exceptions) and the base purchase price would range from approximately $39.8 million to $79.5 million.

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(3) EARNINGS PER SHARE

Basic earnings per share is computed by dividing net income available to common stockholders by the weighted average number of common shares outstanding during each period. Diluted earnings per share includes the effect, if dilutive, of potential common shares associated with stock option and restricted share awards outstanding during each period.

(4) COMMON STOCK

In August 2011, the Board of Directors authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million. The repurchases have been, and will be, carried out in accordance with certain volume, timing and price constraints imposed by the SEC s rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors. Through September 30, 2011, we executed trades to repurchase 590,000 shares at an aggregate cash purchase price of approximately $7.0 million. Of these repurchases, settlements related to 130,000 shares with an aggregate cash purchase price of approximately $1.5 million occurred in October. The repurchased shares are held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans.

(5) ASSET RETIREMENT OBLIGATIONS

Changes in our asset retirement obligations were as follows:

	Nine Months Ended September 30, 2011 (in thousands)
Balance at December 31, 2010	$ 71,583
ASOP Acquisition liabilities assumed	24,225
Accretion expense	12,172
Liabilities incurred	144
Revisions	5,780
Liabilities settled	(25,926)
Balance at September 30, 2011	87,978
Less: End of period, current portion	(23,676)
End of period, noncurrent portion	$ 64,302

(6) INDEBTEDNESS

In connection with the ASOP Acquisition (see Note 2), on February 14, 2011, we issued $210.0 million in aggregate principal amount of our 8.25% Notes due 2018. Furthermore, our credit facility existing on that date was terminated and replaced with a new credit facility. The termination of our prior credit facility during the nine months ended September 30, 2011 resulted in a loss on early extinguishment of debt of $2.4 million, primarily due to writing off the unamortized deferred financing costs associated with the terminated facility.

Senior Notes Offering

On February 14, 2011, we issued the $210.0 million in aggregate principal amount of our 8.25% Notes under an Indenture, dated as of February 14, 2011 (the Indenture). As described in Note 2, Acquisitions, we used the net proceeds from the offering of the 8.25% Notes of $202.0 million, after deducting the initial purchasers discount and offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes. The 8.25% Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest due semi-annually, in arrears, on February 15 and August 15 of each year, commencing on August 15, 2011. The 8.25% Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Notes will mature on February 15, 2018. In connection with the execution of the Indenture, we also entered into a registration rights agreement, dated as of February 14, 2011 (the Registration Rights Agreement).

Under the Registration Rights Agreement, on July 14, 2011, we and our guarantor subsidiaries (the Guarantors) filed a registration statement with the SEC, which was declared effective on July 26, 2011, offering to exchange a new series of freely tradable notes having substantially identical terms as the 8.25% Notes (Exchange Notes) for the 8.25% Notes. Pursuant to this offering, 100% in aggregate principal amount of the 8.25% Notes was exchanged for the Exchange Notes, effective as of August 29, 2011.

On or after February 15, 2015, we may on any one or more occasions redeem all or a part of the 8.25% Notes upon not less than 30 nor more than 60 days notice, at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest on the 8.25% Notes redeemed, to the applicable redemption date, if redeemed during the twelve-month period beginning on February 15th of the years indicated below, subject to the rights of holders of the 8.25% Notes on the relevant record date to receive interest on the relevant interest payment date:

Year	Percentage
2015	104.125%
2016	102.063%
2017 and thereafter	100.000%

Any such redemption and notice may, in our discretion, be subject to the satisfaction of one or more conditions precedent, including but not limited to, the occurrence of a change of control. Unless we default in the payment of the redemption price, interest will cease to accrue on the 8.25% Notes or portions thereof called for redemption on the applicable redemption date.

At any time prior to February 15, 2014, we may, at our option, on any one or more occasions redeem with the net cash proceeds of certain equity offerings up to 35% of the aggregate principal amount of outstanding 8.25% Notes (which amount includes additional notes issued under the Indenture), upon not less than 30 nor more than 60 days prior notice, at a redemption price equal to 108.250% of the principal amount of the notes redeemed, plus accrued and unpaid interest to the redemption date, provided that: (1) at least 65% of the aggregate principal amount of the 8.25% Notes issued under the Indenture (which amount includes additional notes issued under the Indenture) remains outstanding immediately after the occurrence of such redemption; and (2) the redemption occurs within 90 days of the date of the closing of such equity offering. This option to redeem up to 35% of the aggregate principal amount of outstanding 8.25% Notes with the net cash proceeds of certain equity offerings is considered an embedded derivative. We estimate that the fair value of this option at September 30, 2011 is not material.

In addition, we may, at our option, on any one or more occasions redeem all or a part of the 8.25% Notes prior to February 15, 2015 at a redemption price equal to 100% of the principal amount of the 8.25% Notes redeemed plus a make-whole premium as of, and accrued and unpaid interest to the redemption date.

If we experience a change of control (as defined in the Indenture), each holder of the 8.25% Notes will have the right to require us to repurchase all or any part (equal to $2,000 or an integral multiple of $1,000 in excess thereof) of the 8.25% Notes at a price in cash equal to 101% of the aggregate principal amount of the 8.25% Notes repurchased, plus accrued and unpaid interest to the date of repurchase. If we engage in certain asset sales, within 360 days of such sale, we generally must use the net cash proceeds from such sales to repay outstanding senior secured debt (other than intercompany debt or any debt owed to an affiliate), to acquire all or substantially all of the assets, properties or capital stock of one or more companies in our industry, to make capital expenditures or to invest in our business. When any such net proceeds that are not so applied or invested exceed $20.0 million, we must make an offer to purchase the 8.25% Notes and other pari passu debt that is subject to similar asset sale provisions in an aggregate principal amount equal to the excess net cash proceeds. The purchase price of each 8.25% Note (or other pari passu debt) so purchased will be 100% of its principal amount, plus accrued and unpaid interest to the repurchase date, and will be payable in cash.

The Indenture, among other things, limits our ability to: (i) declare or pay dividends, redeem subordinated debt or make other restricted payments; (ii) incur or guarantee additional debt or issue preferred stock; (iii) create or incur liens; (iv) incur dividend or other payment restrictions affecting restricted subsidiaries; (v) consummate a merger, consolidation or sale of all or substantially all of our assets; (vi) enter into sale-leaseback transactions, (vii) enter into transactions with affiliates; (viii) transfer or sell assets; (ix) engage in business other than our current business and reasonably related extensions thereof; or (x) issue or sell capital stock of certain subsidiaries. These covenants are subject to a number of important exceptions and qualifications set forth in the Indenture.

New Senior Credit Facility

On February 14, 2011, we entered into our new credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender. The terms of our new credit facility establish a revolving credit facility with a four-year term that may be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million, subject to an initial borrowing base of $150.0 million. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million, and the amount available under the revolving credit facility is limited by the borrowing base. With the consent of the agent, we also have the ability to increase the aggregate commitments under the new credit facility by up to $100.0 million to the extent that existing and/or future lenders provide additional commitments. Upon the closing of our new credit facility, our then existing credit facility was terminated. We had no amounts drawn under our new credit facility at September 30, 2011.

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The interest rate spread on loans and letters of credit under our new credit facility is based on the level of utilization and range from a base rate plus a margin of 1.00% to 2.00% for base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% for LIBOR borrowings. A commitment fee of 0.5% is payable on the unused portion of the borrowing base. Interest on our base rate borrowings is payable quarterly, in arrears, and interest on our LIBOR borrowings is payable on the last day of each relevant interest period, except that in the case of any interest period that is longer than three months, interest is payable on each successive date three months after the first day of such interest period.

Our new credit facility contains customary covenants, default provisions and collateral requirements. As described in the agreement underlying our new credit facility, we must maintain, for each period for which a covenant certification is required, (a) a minimum current ratio (as defined in the agreement for our new credit facility) of 1.0 to 1.0, (b) a minimum EBITDAX (as defined in the agreement for our new credit facility) to interest expense coverage ratio of 2.5 to 1.0 and (c) a maximum total debt to EBITDAX ratio of 3.5 to 1.0. We are also required to maintain a commodities hedging program that is in compliance with the requirements set forth in our new credit facility. The determination of our borrowing base under our new credit facility is based on our proved reserves, at the sole discretion of the lenders. Our initial borrowing base was $150.0 million and scheduled borrowing base redeterminations will be made on a semi-annual basis on May 1st and November 1st of each year. We recently completed our semi-annual redetermination and our borrowing base was increased to $200.0 million. Our new credit facility also places restrictions on the maximum estimated future production volumes that can be subject to commodity derivative instruments.

Our obligations under our new credit facility, as well as any hedging contracts and treasury management agreements with the lenders or affiliates of lenders, are guaranteed by our material domestic subsidiaries and secured by a pledge of 100% of the stock of each material domestic subsidiary and 66 $^{2}/_{3}$% of each of their foreign material subsidiaries and a first priority lien on substantially all of our and our material subsidiaries assets, including our real property assets and the oil and gas properties to which 85% of the present value of our proved reserves is attributable.

(7) DERIVATIVE TRANSACTIONS

We enter into derivative transactions to reduce exposure to fluctuations in the price of oil and natural gas for a portion of our production. Our fixed-price swaps fix the sales price for a limited amount of our production and, for the contracted volumes, eliminate our ability to benefit from increases in the sales price of the related production. Our put contracts limit our exposure to declines in the sales price of oil for a limited amount of our production. Our collars limit our exposure to declines in the sales price of oil while giving us the ability to benefit from increases to a certain level in the sales price of oil for a limited amount of our production. Derivative contracts are carried at their fair value on the condensed consolidated balance sheets as Fair value of commodity derivative instruments and all unrealized and realized gains and losses are recorded in Gain (loss) on derivative instruments in Other income (expense) in the condensed consolidated statements of operations.

As of September 30, 2011, the following derivative instruments were outstanding:

Oil Contracts

	Fixed-Price Swaps			Puts		
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Floor Price ($/Bbl)**
October 2011 November 2011	2,256	137,600	$ 91.23	1,301	79,350	$ 60.00
December 2011	3,368	104,400	$ 90.25	1,302	40,350	$ 60.00
January 2012 July 2012	2,167	461,500	$ 95.33			
August 2012 November 2012	721	88,000	$ 95.74			
December 2012	1,161	36,000	$ 95.28			
January 2013 July 2013	1,703	361,000	$ 94.28			
August 2013 November 2013	426	52,000	$ 94.18			
December 2013	806	25,000	$ 93.98			

	Collars		
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Strike Price ($/Bbl)**

January 2012 July 2012	1,000	213,000	$ 87.50/123.18
August 2012 November 2012	1,000	122,000	$ 87.50/123.18
December 2012	1,000	31,000	$ 87.50/123.18

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The following table presents information about the components of gain (loss) on derivative instruments:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	(in thousands)			
Derivative contracts:				
Unrealized gain (loss) due to change in fair market value	$ 28,059	$ (3,018)	$ 31,122	$ 8,298
Realized loss on settlement	(1,488)	(900)	(16,245)	(7,183)
Total gain (loss) on derivative instruments	$ 26,571	$ (3,918)	$ 14,877	$ 1,115

(8) FAIR VALUE MEASUREMENTS

ASC Topic 820, Fair Value Measurements and Disclosures, establishes a fair value hierarchy with three levels based on the reliability of the inputs used to determine fair value. These levels include: Level 1, defined as inputs such as unadjusted quoted prices in active markets for identical assets and liabilities; Level 2, defined as inputs other than quoted prices in active markets that are either directly or indirectly observable; and Level 3, defined as unobservable inputs for use when little or no market data exists, therefore requiring an entity to develop its own assumptions.

As of September 30, 2011, we held certain financial assets and liabilities that are required to be measured at fair value on a recurring basis, primarily our commodity derivative instruments. The fair values of derivative instruments were measured using price inputs published by NYMEX. These price inputs are quoted prices for assets and liabilities similar to those held by us and meet the definition of Level 2 inputs within the fair value hierarchy. At September 30, 2011, the carrying amounts and fair values of our derivative instruments are reported as assets totaling $19.0 million. At December 31, 2010, the carrying amounts and fair values of our derivative instruments are reported as assets totaling $0.2 million and liabilities totaling $12.3 million.

On June 9, 2011, we entered into an agreement with an insurance company whereby, if a named wind storm occurs in a specified area of the Gulf of Mexico and that storm meets certain strength criteria, the insurance company will pay a fixed amount of cash proceeds to us. This agreement is considered a weather derivative under the applicable authoritative guidance related to financial instruments. We recognized the premium paid as a current asset, which we are amortizing to expense over the term of the agreement. At September 30, 2011, we estimate that the fair value of this financial instrument approximates the carrying amount of approximately $1.3 million, based on the amount of premium paid, which is a Level 3 input within the fair value hierarchy.

As of September 30, 2011, the carrying amount of our 8.25% Notes is $204.2 million, which reflects the $210.0 million face amount, net of the unamortized amount of initial purchasers discount of $5.8 million. We estimate the fair value of the 8.25% Notes at approximately $191.6 million, based on quoted prices, which are Level 1 inputs within the fair value hierarchy.

We evaluate our capitalized costs of proved oil and natural gas properties for potential impairment when circumstances indicate that the carrying values may not be recoverable. Our assessment of possible impairment of proved oil and natural gas properties is based on our best estimate of future prices, costs and expected net future cash flows by property (generally analogous to a field or lease). An impairment loss is indicated if undiscounted net future cash flows are less than the carrying value of a property. The impairment expense is measured as the shortfall between the net book value of the property and its estimated fair value measured based on the discounted net future cash flows from the property. The inputs used to estimate the fair value of our oil and natural gas properties meet the definition of Level 3 inputs within the fair value hierarchy. Impairments for the nine months ended September 30, 2011 were primarily related to reservoir performance at one of our natural gas producing fields where a production zone depleted prematurely. In the same field we experienced mechanical difficulties attempting to access a behind-pipe zone and currently do not expect that the behind-pipe reserves will be economically recoverable. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value at March 31, 2011. Additional impairments for the nine months ended September 30, 2011 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2011 as compared to June 30, 2011 affecting our deepwater producing well (primarily natural gas) and reservoir performance at two other producing fields, which were determined to have future net cash flows less than their carrying values resulting in the write down of these properties to their estimated fair values.

As addressed in Note 2, Acquisitions, we applied fair value concepts in estimating and allocating the fair value of the ASOP Properties in accordance with purchase accounting for business combinations. The inputs to the estimated fair values of the assets acquired and liabilities assumed are described in Note 2.

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(9) COMMITMENTS AND CONTINGENCIES

We maintain restricted escrow funds in a trust for future abandonment costs at our East Bay field. The trust was originally funded with $15 million and, with accumulated interest, increased to $16.7 million at December 31, 2008. We may draw from the trust upon completion of qualifying abandonment activities at our East Bay field. At September 30, 2011, we had $6.0 million remaining in restricted escrow funds for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our consolidated balance sheets.

We record liabilities when we deliver production that is in excess of our interest in certain properties. In addition to these imbalances, we may, from time to time, be allocated cash sales proceeds in excess of amounts that we estimate are due to us for our interest in production. These allocations may be subject to further review, may require more information to resolve or may be in dispute. In July 2010, we were notified by a purchaser of oil production from one of our non-operated fields that we were allocated, and received sales proceeds from, more oil production than we actually sold to that purchaser. These third party misallocations may date back to 2006. The oil purchaser s initial estimate of the oil volumes misallocated to us was approximately 74,000 barrels, which may be valued at up to $6.9 million based on information provided by the oil purchaser. We have previously recorded an amount that we believe may be payable related to a potential reallocation, which amount is reflected in Accrued expenses in the accompanying condensed consolidated balance sheets as of September 30, 2011.

We and our oil and gas joint interest owners are subject to periodic audits of the joint interest accounts for leases in which we participate and/or operate. As a result of these joint interest audits, amounts payable or receivable by us for costs incurred or revenue distributed by the operator or by us on a lease may be adjusted, resulting in adjustments, increases or decreases, to our net costs or revenues and the related cash flows. Such adjustments may be material. When they occur, these adjustments are recorded in the current period, which generally is one or more years after the related cost or revenue was incurred or recognized by the joint account.

In the ordinary course of business, we are a defendant in various other legal proceedings. We do not expect our exposure in these other proceedings, individually or in the aggregate, to have a material adverse effect on our financial position, results of operations or liquidity.

(10) NEW ACCOUNTING PRONOUNCEMENTS

In May 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs (ASU 2011-04). ASU 2011-04 changes some fair value measurement principles under U.S. GAAP including a change in the valuation premise and the application of premiums and discounts. It also contains certain new disclosure requirements. It is effective for interim and annual periods beginning after December 15, 2011.

In June 2011, the FASB issued ASU No. 2011-05, Comprehensive Income (Topic 220): Presentation of Comprehensive Income (ASU 2011-05), which provides the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. It does not change the items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income. ASU 2011-05 is effective for interim and annual periods beginning after December 15, 2011 and will be applied retrospectively.

(11) SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

In connection with the 8.25% Notes offering described in Note 6, the Guarantors, which include all of our existing 100% owned, direct and indirect domestic subsidiaries (other than immaterial subsidiaries), fully and unconditionally guaranteed, jointly and severally, the payment obligations under our 8.25% Notes and guarantee the payment obligations under the Exchange Notes. The following supplemental financial information sets forth, on a consolidating basis, the balance sheets, statements of operations and cash flow information for Energy Partners, Ltd. (Parent Company Only) and for the Guarantors. We have not presented separate financial statements and other disclosures concerning each individual Guarantor because management has determined that such information is not material to investors.

The supplemental condensed consolidating financial information has been prepared pursuant to the rules and regulations for condensed financial information and does not include all disclosures included in annual financial statements. Certain reclassifications were made to conform all of the financial information to the financial presentation on a consolidated basis. The principal eliminating entries eliminate investments in subsidiaries, intercompany balances and intercompany revenues and expenses.

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Supplemental Condensed Consolidating Balance Sheet

As of September 30, 2011

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 87,268	$	$	$ 87,268
Accounts receivable	81,067	133	(53,131)	28,069
Other current assets	19,544	1,674		21,218
Total current assets	187,879	1,807	(53,131)	136,555
Property and equipment	772,732	232,497		1,005,229
Less accumulated depreciation, depletion and amortization	(214,305)	(46,021)		(260,326)
Net property and equipment	558,427	186,476		744,903
Investment in affiliates	85,534		(85,534)	
Notes receivable, long-term		69,000	(69,000)	
Other assets	20,700			20,700
	852,540	257,283	(207,665)	902,158
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 77,898	$ 64,813	$ (53,131)	$ 89,580
Deferred tax liabilities	6,537			6,537
Total current liabilities	84,435	64,813	(53,131)	96,117
Long-term debt	204,216	69,000	(69,000)	204,216
Other liabilities	60,368	37,936		98,304
	349,019	171,749	(122,131)	398,637
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	40	98	(98)	40
Additional paid-in capital	504,540	84,900	(84,900)	504,540
Retained earnings	4,472	533	(533)	4,472
Treasury stock, at cost	(5,531)			(5,531)
Total stockholders equity	503,521	85,534	(85,534)	503,521
	852,540	257,283	(207,665)	902,158

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Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2010

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
ASSETS				
Current assets:				
Cash and cash equivalents	$ 33,553	$	$	$ 33,553
Accounts receivable	73,040	259	(49,768)	23,531
Other current assets	4,508	1,674		6,182
Total current assets	111,101	1,933	(49,768)	63,266
Property and equipment	512,569	206,578		719,147
Less accumulated depreciation, depletion and amortization	(137,284)	(30,771)		(168,055)
Net property and equipment	375,285	175,807		551,092
Investment in affiliates	76,236		(76,236)	
Notes receivable, long-term		69,000	(69,000)	
Other assets	12,548			12,548
	575,170	246,740	(195,004)	626,906
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities:				
Accounts payable and accrued expenses	$ 50,756	$ 62,666	$ (49,768)	$ 63,654
Fair value of commodity derivative instruments	12,320			12,320
Total current liabilities	63,076	62,666	(49,768)	75,974
Long-term debt		69,000	(69,000)	
Other liabilities	38,978	38,838		77,816
	102,054	170,504	(118,768)	153,790
Stockholders equity:				
Preferred stock		3	(3)	
Common stock	40	98	(98)	40
Additional paid-in capital	502,556	84,900	(84,900)	502,556
Retained earnings	(29,480)	(8,765)	8,765	(29,480)
Total stockholders equity	473,116	76,236	(76,236)	473,116
	575,170	246,740	(195,004)	626,906

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Supplemental Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2011

	Parent Company Only	Guarantors	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 61,196	$ 23,657	$	$ 84,853
Other	3,752	29	(3,750)	31
	64,948	23,686	(3,750)	84,884
Costs and expenses:				
Lease operating expenses	14,970	4,296		19,266
Taxes, other than on earnings	210	3,283		3,493
Exploration expenditures, dry hole cost and impairments	6,458	38		6,496
Depreciation, depletion, amortization and accretion	24,155	7,134		31,289
General and administrative	4,339	3,872	(3,750)	4,461
Other expenses	5,051	(824)		4,227
Total costs and expenses	55,183	17,799	(3,750)	69,232
Income from operations	9,765	5,887		15,652
Other income (expense):				
Interest expense, net	(4,999)			(4,999)
Gain on derivative instruments	26,571			26,571
Income from equity investments	3,742		(3,742)	
Income before income taxes	35,079	5,887	(3,742)	37,224
Deferred income tax expense	(11,621)	(2,145)		(13,766)
Net income	$ 23,458	$ 3,742	$ (3,742)	$ 23,458

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Supplemental Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2010

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 37,553	$ 18,684	$	$ 56,237
Other	3,752	32	(3,750)	34
	41,305	18,716	(3,750)	56,271
Costs and expenses:				
Lease operating expenses	9,963	2,894		12,857
Taxes, other than on earnings	864	2,242		3,106
Exploration expenditures, dry hole cost and impairments	12,662	995		13,657
Depreciation, depletion, amortization and accretion	20,508	8,015		28,523
General and administrative	4,742	3,815	(3,750)	4,807
Other expenses	507			507
Total costs and expenses	49,246	17,961	(3,750)	63,457
Income (loss) from operations	(7,941)	755		(7,186)
Other income (expense):				
Interest expense, net	(718)			(718)
Loss on derivative instruments	(3,918)			(3,918)
Income from equity investments	476		(476)	
Income (loss) before income taxes	(12,101)	755	(476)	(11,822)
Deferred income tax benefit (expense)	4,255	(279)		3,976
Net income (loss)	$ (7,846)	$ 476	$ (476)	$ (7,846)

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Supplemental Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2011

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 175,008	$ 69,858	$	$ 244,866
Other	11,256	91	(11,250)	97
	186,264	69,949	(11,250)	244,963
Costs and expenses:				
Lease operating expenses	38,461	14,044		52,505
Taxes, other than on earnings	806	9,700		10,506
Exploration expenditures, dry hole cost and impairments	21,297	243		21,540
Depreciation, depletion, amortization and accretion	64,874	20,379		85,253
General and administrative	14,202	11,592	(11,250)	14,544
Other expenses	7,444	(814)		6,630
Total costs and expenses	147,084	55,144	(11,250)	190,978
Income from operations	39,180	14,805		53,985
Other income (expense):				
Interest expense, net	(12,416)			(12,416)
Gain on derivative instruments	14,877			14,877
Loss on early extinguishment of debt	(2,377)			(2,377)
Income from equity investments	9,298		(9,298)	
Income before income taxes	48,562	14,805	(9,298)	54,069
Deferred income tax expense	(14,610)	(5,507)		(20,117)
Net income	$ 33,952	$ 9,298	$ (9,298)	$ 33,952

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Supplemental Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2010

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
Revenue:				
Oil and natural gas	$ 138,476	$ 46,607	$	$ 185,083
Other	11,256	98	(11,250)	104
	149,732	46,705	(11,250)	185,187
Costs and expenses:				
Lease operating expenses	29,908	11,066		40,974
Taxes, other than on earnings	1,891	5,528		7,419
Exploration expenditures, dry hole cost and impairments	26,953	995		27,948
Depreciation, depletion, amortization and accretion	72,986	17,942		90,928
General and administrative	13,645	11,475	(11,250)	13,870
Other expenses	1,800			1,800
Total costs and expenses	147,183	47,006	(11,250)	182,939
Income (loss) from operations	2,549	(301)		2,248
Other income (expense):				
Interest expense, net	(8,768)			(8,768)
Gain on derivative instruments	1,115			1,115
Loss on early extinguishment of debt	(5,627)			(5,627)
Loss from equity investments	(200)		200	
Loss before income taxes	(10,931)	(301)	200	(11,032)
Deferred income tax benefit	3,591	101		3,692
Net loss	$ (7,340)	$ (200)	$ 200	$ (7,340)

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Supplemental Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2011

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 80,045	$ 25,890	$	$ 105,935
Cash flows provided by (used in) investing activities:				
Property acquisitions	(196,533)			(196,533)
Exploration and development expenditures	(23,356)	(25,890)		(49,246)
Other property and equipment additions	(833)			(833)
Decrease in restricted cash	2,467			2,467
Net cash used in investing activities	(218,255)	(25,890)		(244,145)
Cash flows provided by (used in) financing activities:				
Proceeds from long-term debt	203,794			203,794
Deferred financing costs	(6,465)			(6,465)
Purchase of shares into treasury	(5,523)			(5,523)
Exercise of stock options	119			119
Net cash provided by financing activities	191,925			191,925
Net increase in cash and cash equivalents	53,715			53,715
Cash and cash equivalents at the beginning of the period	33,553			33,553
Cash and cash equivalents at the end of the period	$ 87,268	$	$	$ 87,268

Supplemental Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2010

	Parent Company Only	Guarantors	Eliminations	Consolidated
		(In thousands)		
Net cash provided by operating activities	$ 65,082	$ 31,910	$	$ 96,992
Cash flows provided by (used in) investing activities:				
Property acquisitions	(623)			(623)
Exploration and development expenditures	(11,122)	(31,910)		(43,032)
Decrease in restricted cash	12,166			12,166
Net cash provided by (used in) investing activities	421	(31,910)		(31,489)
Cash flows provided by (used in) financing activities:				
Proceeds from long-term debt	20,394			20,394
Repayments of long-term debt	(82,382)			(82,382)
Deferred financing costs	(33)			(33)
Net cash used in financing activities	(62,021)			(62,021)

Net increase in cash and cash equivalents	3,482			3,482
Cash and cash equivalents at the beginning of the period	26,745			26,745
Cash and cash equivalents at the end of the period	$ 30,227	$	$	$ 30,227

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

Statements we make in this Quarterly Report on Form 10-Q (the Quarterly Report) that express a belief, expectation or intention, as well as those that are not historical fact, may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Our forward-looking statements are subject to various risks, uncertainties and assumptions, including those to which we refer under the headings Cautionary Statement Concerning Forward-Looking Statements and Risk Factors in Items 1 and 1A of Part 1 of our Annual Report on Form 10-K for the year ended December 31, 2010, as amended (the 2010 Annual Report).

OVERVIEW

We were incorporated as a Delaware corporation in January 1998 and operate in a single segment as an independent oil and natural gas exploration and production company. Our current operations are concentrated in the U.S. Gulf of Mexico shelf focusing on state and federal waters offshore Louisiana, which we consider our core area. We have focused on acquiring and developing assets in this region, as it offers a balanced and expansive array of existing and prospective exploration, exploitation and development opportunities in both established productive horizons and deeper geologic formations.

We maintain a website at *www.eplweb.com* that contains information about us, including links to our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all related amendments as soon as reasonably practicable after providing such reports to the Securities and Exchange Commission (the SEC).

We use the successful efforts method of accounting for oil and natural gas producing activities. Under this method, we capitalize lease acquisition costs, costs to drill and complete exploration wells in which proven reserves are discovered and costs to drill and complete development wells. Exploratory drilling costs are charged to expense if and when activities result in no reserves in commercial quantities. Seismic, geological and geophysical, and delay rental expenditures are expensed as they are incurred. We conduct various exploration and development activities jointly with others and, accordingly, recorded amounts for our oil and natural gas properties reflect only our proportionate interest in such activities. Our 2010 Annual Report includes a discussion of our critical accounting policies, which have not changed significantly since the end of the last fiscal year.

We produce both oil and natural gas. Throughout this Quarterly Report, when we refer to total production, total reserves, percentage of production, percentage of reserves, or any similar term, we have converted our natural gas reserves or production into barrel equivalents. For this purpose, six thousand cubic feet of natural gas is equal to one barrel of oil, which is based on the relative energy content of natural gas and oil. Natural gas liquids are aggregated with oil in this Quarterly Report.

Recent Developments

The ASOP Acquisition and Notes Offering. On February 14, 2011, we acquired an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests surrounding the Mississippi River delta and a related gathering system (the ASOP Properties) from Anglo-Suisse Offshore Partners, LLC (ASOP) for $200.7 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2011 (the ASOP Acquisition). As of December 31, 2010, the ASOP Properties had estimated proved reserves of approximately 8.1 Mmboe, of which 84% were oil and 76% were proved developed reserves. Of these proved developed reserves, 88% were oil reserves. The ASOP Properties acquired in the ASOP Acquisition:

- included 59 producing wells in three complexes;
- had average daily production of approximately 3,620 Boe per day for the period from February 14, 2011 to September 30, 2011;
- included 48,106 gross and 37,402 net acres; and
- included related gathering lines.

The ASOP Acquisition was financed with the proceeds from the sale of $210 million in aggregate principal amount of 8.25% senior notes due 2018 (the 8.25% Notes) offered to qualified institutional buyers pursuant to Rule 144A promulgated under the Securities Act of 1933, as amended (the Securities Act), and to persons outside the United States pursuant to Regulation S promulgated under the Securities Act. After deducting the initial purchasers discount and offering expenses, we realized net proceeds of approximately $202 million. On July 14, 2011, we and our guarantor subsidiaries (the Guarantors) filed a registration statement with the SEC, which was declared effective on July 26, 2011, offering to exchange a new series of freely tradable notes having substantially identical terms as the 8.25% Notes (Exchange Notes) for the 8.25% Notes. Pursuant to this offering, 100% in aggregate principal amount of the 8.25% Notes was exchanged for the Exchange Notes, effective as of August 29, 2011. On February 14, 2011, we also entered into an agreement for a new senior credit facility. See Liquidity and Capital Resources for more information regarding the 8.25% Notes and the new senior credit facility.

The ASOP Acquisition provides an opportunity to significantly increase our reserves, production volumes and drilling portfolio, while maintaining our focus on oil-weighted assets in our core area of expertise in the Gulf of Mexico shelf. The ASOP Acquisition also provides us with access to infrastructure and extensive acreage, with significant exploitation and development potential. We are pursuing exploitation of the ASOP Properties, including recompletions, well reactivations and development drilling, while we analyze the potential for higher-impact exploration prospects. We operate properties containing approximately 60% of the proved reserves attributable to the ASOP Properties. In conjunction with the ASOP Acquisition, we implemented a three-year commodity price hedging program weighted towards oil to help reduce commodity price risks associated with future oil production.

The Main Pass Acquisition. On October 28, 2011, we entered into a purchase and sale agreement with Stone Energy Offshore, L.L.C. (Seller) relating to the purchase (the Main Pass Acquisition) of certain interests in producing oil and natural gas assets in the shallow-water central Gulf of Mexico shelf (the Main Pass Interests) for $80.0 million in cash, subject to customary adjustments to reflect the economic effective date of November 1, 2011. The Main Pass Interests currently produce approximately 900 barrels of oil equivalent per day, approximately 96% of which is oil. The Main Pass Interests consist of additional interests in the Main Pass 296/311 complex that was included in the assets we purchased from ASOP in February 2011, along with other unit interests in the Main Pass complex and an interest in a Main Pass 295 primary term lease. We estimate that the proved reserves as of the November 1, 2011 economic effective date totaled approximately 2.6 Mmboe, all of which were proved developed reserves and approximately 96% of which were oil reserves. The estimated asset retirement obligation to be assumed and recorded on our balance sheet as a result of the Main Pass Acquisition is expected to total approximately $4 million. The consummation of the Main Pass Acquisition is subject to customary closing conditions and is expected to close in November 2011. We intend to fund the Main Pass Acquisition with cash on hand.

The Main Pass Interests are not operated by Seller, and the other working interest owner and current operator of the Main Pass 296/311 complex has a preferential right under the applicable operating agreements to purchase the Main Pass Interests as a result of the Main Pass Acquisition. However, even if the operator exercises its preferential purchase right, the applicable operating agreements limit the amount that the operator can acquire by exercising the preferential right. In that case, the Main Pass Acquisition would still be completed, but, depending upon the various scenarios of the other working interest owner exercising at least one or more of the preferential rights, we would generally acquire 50% of the Main Pass Interests (with certain exceptions) and the base purchase price would range from approximately $39.8 million to $79.5 million.

Overview and Outlook

For full year 2011 we expect to spend between $110 and $115 million (excluding the cost of acquisitions), $90 to $100 million of which is related to development of our existing Gulf of Mexico shelf asset base including the ASOP Properties and $15 to $20 million of which is related to exploration projects. We also plan to spend approximately $27 million in 2011 on plugging, abandonment and other decommissioning activities. Our key areas of operations and our plans for future exploration and development activities do not include any deepwater areas. We allocate capital in a rigorous and disciplined manner intended to achieve an overall lower risk capital expenditure profile that focuses on maximizing rate of return and requires projects to compete on that basis. This allocation has led us to focus on oil-weighted projects, which has resulted in the maintenance of our upward trend in our oil production volumes as compared with the decline in our natural gas volumes.

We continually review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects so that we can act quickly as acquisition opportunities become available. We intend to focus our acquisition strategy on Gulf of Mexico shelf assets that are characterized by production-weighted reserves, seismic coverage and operated positions. We intend to use acquisitions of this type as a key method to replace and grow reserves and production, because we believe this strategy increases production and cash flow visibility while reducing dry hole and exploration risk. We believe our expertise in the Gulf of Mexico shelf and in plugging and abandonment operations allows us to efficiently evaluate acquisitions and to operate any properties we eventually acquire.

We continue to generate prospects, strive to maintain an extensive inventory of drillable prospects in-house and maintain exposure to new opportunities through relationships with industry partners. Generally, we fund any exploration and development expenditures with internally generated cash flows.

Our longer term operating strategy is to increase our oil and natural gas reserves and production while focusing on reducing exploration and development costs and operating costs to remain competitive with our offshore Gulf of Mexico industry peers.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as oil and natural gas prices, tropical weather, economic, political and regulatory developments and availability of other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil and natural gas could materially adversely affect our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. See Risk Factors in Item 1A of our 2010 Annual Report and Item 1A of Part II of this Quarterly Report for a more detailed discussion of these risks.

We believe that we possess a core competency in plugging, abandonment and decommissioning operations which allows us to reduce our overall costs in that area of operations, enabling us to achieve our objectives of prudently removing idle infrastructure throughout the remaining productive lives of our fields and, over time, to reduce ongoing lease operating expenses (LOE) associated with maintaining idle infrastructure.

Results of Operations

Three Months Ended September 30, 2011

During the three months ended September 30, 2011, we completed three (3) development drilling operations and seven (7) recompletion operations, all of which were successful. As of September 30, 2011, we were drilling the first well of a four-well exploratory drilling program, and that well was successfully completed in October 2011.

Our operating results for the three months ended September 30, 2011, compared to the three months ended September 30, 2010, reflect significantly higher average selling prices for our oil. The product mix for our production for the three months ended September 30, 2011 was 75% oil (including natural gas liquids), compared to 48% oil (including natural gas liquids) for the comparable period in 2010. This change in product mix results from a decline in natural gas production and a decline in production of natural gas liquids, which we expect to continue for the remainder of 2011, partially offset by an increase in oil production. Additionally, our results for the three months ended September 30, 2011 include production from the recently acquired ASOP Properties of 3,684 Boe per day. We expect our oil production to increase during the remainder of 2011. We also expect our full-year 2011 oil production to increase as compared to our full-year 2010 oil production.

For the three months ended September 30, 2011, our revenues increased 51% as compared to the three months ended September 30, 2010, due primarily to the higher oil sales prices and the increase in oil production. Our overall production volumes, including barrel of oil equivalent natural gas volumes, decreased by 18% for the three months ended September 30, 2011 when compared to the three months ended September 30, 2010. Our Gulf of Mexico shelf production decreased 13% in the three months ended September 30, 2011, as compared to the quarter ended September 30, 2010, due primarily to production declines in our predominantly natural gas fields, partially offset by production from the ASOP Properties. In addition, our deepwater production, primarily natural gas, declined 56% for the quarter ended September 30, 2011, as compared to the quarter ended September 30, 2010, primarily due to natural reservoir decline from our deepwater well. In addition, production from this deepwater well has been, and will continue to be during the fourth quarter, curtailed for extended periods due to third party downstream facility modifications. We expect that our deepwater production will continue to decline in 2011.

In addition to the items addressed above, our net income for the three months ended September 30, 2011, as compared to the net loss for the three months ended September 30, 2010, primarily reflects a significant unrealized gain on derivative instruments and a decrease in impairments.

Our effective income tax rate for the three months ended September 30, 2011 and 2010 was 37.0% and 33.6%, respectively. The increase in our effective income tax rate is primarily related to estimated state income taxes. The income tax benefit recorded on the net loss for the three months ended September 30, 2010 was reduced due to applying the change in our estimated effective income tax rate for the full year 2010, from 36% to 37.4%, to our net deferred tax liabilities. The change in our estimated effective income tax rate for 2010 was related to state income taxes.

Nine Months Ended September 30, 2011

During the nine months ended September 30, 2011, we completed three (3) development drilling operations, all of which were successful, and twenty-two (22) recompletion operations, nineteen (19) of which were successful. As of September 30, 2011, we were drilling the first well of a four-well exploratory drilling program, and that well was successfully completed in October 2011.

Our operating results for the nine months ended September 30, 2011, compared to the nine months ended September 30, 2010, reflect significantly higher average selling prices for our oil and lower average selling prices for our natural gas. The product mix for our production for the nine months ended September 30, 2011 was 71% oil (including natural gas liquids), compared to 47% oil (including natural gas liquids) for the comparable period in 2010. This change in product mix results from a decline in natural gas production and a decline in production of natural gas liquids, which we expect to continue for the remainder of 2011, partially offset by an increase in oil production. Additionally, our results for the nine months ended September 30, 2011 include production from the recently acquired ASOP Properties of 3,620 Boe per day.

For the nine months ended September 30, 2011, our revenues increased 32% as compared to the nine months ended September 30, 2010, due primarily to the higher oil sales prices and the increase in oil production. Our overall production volumes, including barrel of oil equivalent natural gas volumes, decreased by 24% for the nine months ended September 30, 2011 when compared to the nine months ended September 30, 2010. Our Gulf of Mexico shelf production decreased 22% in the nine months ended September 30, 2011, as compared to the nine months ended

September 30, 2010, due primarily to production declines in our predominantly natural gas fields, partially offset by production from the ASOP Properties. In addition, our deepwater production, primarily natural gas, declined 43% for the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010, primarily due to natural reservoir decline from our deepwater well.

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Our effective income tax rate for the nine months ended September 30, 2011 and 2010 was 37.2% and 33.5%, respectively. The increase in our effective income tax rate is primarily related to estimated state income taxes. The income tax benefit recorded on the net loss for the nine months ended September 30, 2010 was reduced due to applying the change in our estimated effective income tax rate for the full year 2010, from 36% to 37.4%, to our net deferred tax liabilities. The change in our estimated effective income tax rate for 2010 was related to state income taxes.

RESULTS OF OPERATIONS

The following table presents information about our oil and natural gas operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net production (per day):				
Oil (Bbls)	8,034	6,219	7,634	6,615
Natural gas (Mcf)	16,358	41,102	18,888	45,158
Total (Boe)	10,760	13,069	10,782	14,142
Average sales prices:				
Oil (per Bbl)	$ 106.23	$ 69.72	$ 106.71	$ 70.60
Natural gas (per Mcf)	4.21	4.32	4.35	4.67
Total (per Boe)	85.72	46.77	83.19	47.94
Oil and natural gas revenues (in thousands):				
Oil	$ 78,518	$ 39,891	$ 222,410	$ 127,507
Natural gas	6,335	16,346	22,456	57,576
Total	84,853	56,237	244,866	185,083
Impact of derivatives instruments settled during the period(1):				
Oil (per Bbl)	$ (2.01)	$ (1.57)	$ (7.79)	$ (4.03)
Natural gas (per Mcf)		$		$ 0.01
Average costs (per Boe):				
LOE	$ 19.46	$ 10.69	$ 17.84	$ 10.61
Depreciation, depletion and amortization (DD&A)	26.76	21.06	24.83	21.05
Accretion of liability for asset retirement obligations	4.84	2.66	4.14	2.50
Taxes, other than on earnings	3.53	2.58	3.57	1.92
General and administrative (G&A) expenses	4.51	4.00	4.94	3.59
Increase (decrease) in oil and natural gas revenues due to:				
Changes in prices of oil	$ 20,889		$ 65,215	
Changes in production volumes of oil	17,738		29,688	
Total increase in oil sales	38,627		94,903	
Changes in prices of natural gas	$ (416)		$ (3,887)	
Changes in production volumes of natural gas	(9,595)		(31,233)	
Total decrease in natural gas sales	(10,011)		(35,120)	

(1) See Other Income and Expense section for further discussion of the impact of derivative instruments.

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

Revenue and Net Income (Loss)

	Three Months Ended September 30, 2011	2010		
		(in thousands)	$ Change	% Change
Oil and natural gas revenues	$ 84,853	$ 56,237	$ 28,616	51%
Net income (loss)	23,458	(7,846)	31,304	NM

NM Not Meaningful

Our oil and natural gas revenues increased primarily due to a 52% increase in average selling prices for our oil and a 29% increase in oil production in the three months ended September 30, 2011 as compared to the three months ended September 30, 2010, offset by a 60% decline in natural gas production in the three months ended September 30, 2011 as compared to the three months ended September 30, 2010. The percentage of production represented by oil has increased for us. Oil represented 75% of total production for the three months ended September 30, 2011, as compared to 48% of total production for the three months ended September 30, 2010.

Operating Expenses

Our operating expenses primarily consist of the following:

	Three Months Ended September 30, 2011	2010		
		(in thousands)	$ Change	% Change
LOE	$ 19,266	$ 12,857	$ 6,409	50%
Exploration expenditures and dry hole costs	973	1,291	(318)	(25)%
Impairments	5,523	12,366	(6,843)	(55)%
DD&A, including accretion expense	31,289	28,523	2,766	10%
G&A expenses	4,461	4,807	(346)	(7)%
Taxes, other than on earnings	3,493	3,106	387	12%

LOE has increased primarily due to the addition of the ASOP Properties in 2011. The increase in our LOE per Boe is due to the increase in our oil production as a percentage of our total production, which generally has a higher per Boe cost to produce than natural gas. The percentage of our production represented by oil increased from 48% for the three months ended September 30, 2010 to 75% for the three months ended September 30, 2011.

Impairments for the three months ended September 30, 2011 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2011 as compared to June 30, 2011 affecting our deepwater producing well (primarily natural gas), which was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value as of September 30, 2011. Additionally, we increased our estimate of future abandonment costs for our deepwater fields in the three months ended September 30, 2011. Impairments for the three months ended September 30, 2010 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well.

DD&A per Boe increased primarily due to the acquisition of the ASOP Properties, which have higher per Boe DD&A rates because they were recorded at estimated fair values at the February 14, 2011 acquisition date.

G&A expenses, which include non-cash stock based compensation of $0.6 million and $0.3 million in the three months ended September 30, 2011 and 2010, respectively, decreased in the three months ended September 30, 2011 as compared to the three months ended September 30, 2010, due primarily to decreases in employee related costs.

Taxes, other than on earnings, increased in the three months ended September 30, 2011 as compared to the three months ended September 30, 2010, due primarily to higher average sales prices for oil (for which production taxes are based on selling price).

Other Income and Expense

Interest expense increased in the three months ended September 30, 2011, as compared to the three months ended September 30, 2010. For the three months ended September 30, 2011, our interest expense consists primarily of interest on our 8.25% Notes issued in connection with the ASOP Acquisition. For the three months ended September 30, 2010, our interest expense consisted primarily of interest on the term portion of our previous credit facility.

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Other income (expense) in the three months ended September 30, 2011 includes a net gain of $26.6 million consisting of an unrealized gain of $28.1 million due to the change in fair market value of derivative instruments and a loss of $1.5 million on derivative instruments settled during the quarter primarily from the impact of our oil fixed-price swaps. Other income (expense) in the three months ended September 30, 2010 includes a net loss of $3.9 million consisting of an unrealized loss of $3.0 million due to the change in fair market value of derivative instruments and a loss of $0.9 million on derivative instruments settled during the quarter primarily from the impact of our oil fixed-price swaps.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Revenue and Net Income (Loss)

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (in thousands)	$ Change	% Change
Oil and natural gas revenues	$ 244,866	$ 185,083	$ 59,783	32%
Net income (loss)	33,952	(7,340)	41,292	NM

NM Not Meaningful

Our oil and natural gas revenues increased primarily due to a 51% increase in average selling prices for our oil and a 15% increase in oil production in the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, offset in part by a 58% decline in natural gas production in the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The percentage of production represented by oil has increased for us. Oil represented 71% of total production for the nine months ended September 30, 2011, as compared to 47% of total production for the nine months ended September 30, 2010.

Operating Expenses

Our operating expenses primarily consist of the following:

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010 (in thousands)	$ Change	% Change
LOE	$ 52,505	$ 40,974	$ 11,531	28%
Exploration expenditures and dry hole costs	2,343	3,928	(1,585)	(40)%
Impairments	19,197	24,020	(4,823)	(20)%
DD&A, including accretion expense	85,253	90,928	(5,675)	(6)%
G&A expenses	14,544	13,870	674	5%
Taxes, other than on earnings	10,506	7,419	3,087	42%

LOE has increased primarily due to the addition of the ASOP Properties in 2011. The increase in our LOE per Boe is due to the increase in our oil production, which generally has a higher per Boe cost to produce than natural gas. The percentage of our production represented by oil increased from 47% for the nine months ended September 30, 2010 to 71% for the nine months ended September 30, 2011.

Exploration expenditures in the nine months ended September 30, 2011 includes $0.6 million of delay rentals. In the nine months ended September 30, 2010, we completed drilling of one exploratory dry hole and we also recorded approximately $1.0 million of dry hole costs related to one exploratory dry hole which we completed drilling in October 2010. In addition, the expense in the nine months ended September 30, 2010 includes $1.1 million of seismic expenditures and delay rentals.

Impairments for the nine months ended September 30, 2011 were primarily related to reservoir performance at one of our natural gas producing fields where a production zone depleted prematurely. In the same field we experienced mechanical difficulties attempting to access a behind-pipe zone and currently do not expect that the behind-pipe reserves will be economically recoverable. This field was determined to have future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value at March 31, 2011. Additional impairments for the nine months ended September 30, 2011 were primarily related to the decline in our estimate of future natural gas prices as of September 30, 2011 as compared to June 30, 2011 affecting our deepwater producing well (primarily natural gas) and reservoir performance at two other producing fields. Impairment expense for the nine months ended September 30, 2010 was primarily related to the decline in our estimate of future natural gas prices as of September 30, 2010 as compared to June 30, 2010 affecting two producing fields, including our deepwater producing well, and to reservoir performance of one of these fields and one additional producing field.

DD&A declined as a result of the overall Boe production declines described above. DD&A per Boe increased primarily due to the acquisition of the ASOP Properties which have higher per Boe DD&A rates because they were recorded at estimated fair values at the February 14, 2011 acquisition date.

G&A expenses, which include non-cash stock based compensation of $1.8 million and $1.0 million in the nine months ended September 30, 2011 and 2010, respectively, increased in the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010, primarily as a result of costs incurred in our acquisition efforts in the first quarter of 2011 and the increase in non-cash stock based compensation, partially offset by decreases in employee related costs. Acquisition costs related to the ASOP Acquisition were $0.5 million in the nine months ended September 30, 2011.

Taxes, other than on earnings, increased in the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, due primarily to higher average sales prices for oil (for which production taxes are based on selling price).

Other Income and Expense

Interest expense increased in the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010. For the nine months ended September 30, 2011, our interest expense consists primarily of interest on our 8.25% Notes issued in connection with the ASOP Acquisition. For the nine months ended September 30, 2010, interest expense consisted primarily of interest expense on our PIK Notes and the term portion of our previous credit facility, which were outstanding during that period. We redeemed all of our outstanding PIK Notes on June 28, 2010.

Other income (expense) in the nine months ended September 30, 2011 includes a net gain of $14.9 million consisting of an unrealized gain of $31.1 million due to the change in fair market value of derivative instruments and a loss of $16.2 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps. Other income (expense) in the nine months ended September 30, 2010 includes a net gain of $1.1 million consisting of an unrealized gain of $8.3 million due to the change in fair market value of derivative instruments and a loss of $7.2 million on derivative instruments settled during the period primarily from the impact of our oil fixed-price swaps.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity and Capital Resources

ASOP Acquisition and Notes Offering. On February 14, 2011, we issued $210 million in aggregate principal amount of the 8.25% Notes. We used the net proceeds from the offering of the 8.25% Notes of $202 million, after deducting the initial purchasers discount and offering expenses payable by us, to acquire the ASOP Properties for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011, and for general corporate purposes. The 8.25% Notes bear interest from the date of their issuance at an annual rate of 8.25% with interest on outstanding notes payable semi-annually, in arrears, on February 15 and August 15 of each year, commencing on August 15, 2011. The 8.25% Notes are fully and unconditionally guaranteed, jointly and severally, on an unsecured senior basis initially by each of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries). The 8.25% Notes will mature on February 15, 2018. For more information on our 8.25% Notes, see Note 6, Indebtedness, of our condensed consolidated financial statements contained in Part I, Item 1 of this Quarterly Report.

New Senior Credit Facility. On February 14, 2011, we entered into our new credit facility with BMO Capital Markets, as lead arranger, Bank of Montreal, as administrative agent and a lender. Under the terms of the credit agreement, our new credit facility established a revolving credit facility with a four-year term that may be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million, subject to an initial borrowing base of $150.0 million. The new credit facility is secured by substantially all of our assets, including mortgages on at least 85% of our oil and gas properties and the stock of certain wholly-owned subsidiaries. The borrowing base under the new credit facility has been determined at the discretion of the lenders, based on the collateral value of our proved reserves, and is subject to potential special and regular semi-annual redeterminations. We recently completed our semi-annual redetermination and our borrowing base was increased to $200.0 million. Borrowings under our new credit facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. We had no amounts drawn under our new credit facility at September 30, 2011.

Stock Repurchase Program. In August 2011, the Board of Directors authorized a program for the repurchase of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million. The repurchases have been, and will be, carried out in accordance with certain volume, timing and price constraints imposed by the SEC s rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors. Through the date of this report, we have repurchased 590,000 shares at an aggregate cash purchase price of approximately $7.0 million. Such shares are held in treasury and could be used to provide available shares for possible resale in future public or private offerings and our employee benefit plans.

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Sources and Uses of Capital. As of September 30, 2011, we had cash and cash equivalents of $87.3 million and no borrowings outstanding under our new credit facility. At the closing of our 8.25% Notes offering on February 14, 2011, our prior credit facility was replaced with our new credit facility, which had an initial borrowing base of $150.0 million and was recently increased to $200.0 million. There is no term loan component in our new credit facility.

On October 28, 2011, we entered into a purchase and sale agreement to acquire the Main Pass Interests for $80.0 million in cash, subject to customary adjustments to reflect the economic effective date of November 1, 2011. The consummation of the Main Pass Acquisition is subject to customary closing conditions and is expected to close in November 2011. We intend to fund the Main Pass Acquisition with cash on hand. See Overview Recent Developments for more information regarding the Main Pass Acquisition.

For full year 2011 we expect to spend between $110 and $115 million (excluding the cost of acquisitions) on development and exploration projects. We also plan to spend approximately $27 million in 2011 on plugging, abandonment and other decommissioning activities. Our key areas of operations and our plans for future exploration and development activities do not include any deepwater areas.

We continually review and monitor opportunities to acquire producing properties, leasehold acreage and drilling prospects so that we can act quickly as acquisition opportunities become available. We intend to focus our acquisition strategy on Gulf of Mexico shelf assets that are characterized by production-weighted reserves, seismic coverage and operated positions. We intend to use acquisitions of this type as a key method to replace and grow reserves and production, because we believe this strategy increases production and cash flow visibility while reducing dry hole and exploration risk. We may fund future acquisitions with a combination of cash on hand, borrowings on our credit facility and issuances of one or more debt and equity securities under our universal shelf registration statement that became effective under the Securities Act of 1933 in July 2011.

We believe our expertise in the Gulf of Mexico shelf and in plugging and abandonment operations allows us to effectively evaluate acquisitions and to operate any properties we eventually acquire. Our deepwater assets do not fit with our long-term strategy, and there are no current plans to develop these interests. As such, we may monetize or trade these assets.

At September 30, 2011, we had working capital of $40.4 million, compared to a working capital deficit of $12.7 million at December 31, 2010. We have experienced, and may experience in the future, substantial working capital deficits. Our working capital deficits have historically resulted from increased accounts payable and accrued expenses related to ongoing exploration and development costs, which may be capitalized as noncurrent assets.

We maintain restricted escrow funds in a trust for future plugging, abandonment and other decommissioning costs at our East Bay field. The trust was originally funded with $15.0 million and, with accumulated interest, had increased to $16.7 million at December 31, 2008. We have made draws to date of $10.7 million, with $2.5 million drawn in 2011. We were able to draw from the trust upon the authorization, and subsequent completion, of qualifying abandonment activities at our East Bay field. As of the date of this Quarterly Report, we had $6.0 million remaining in restricted escrow funds for decommissioning work in our East Bay field, which will remain restricted until substantially all required decommissioning in the East Bay field is complete. Amounts on deposit in the trust account are reflected in Restricted cash on our condensed consolidated balance sheets.

The Bureau of Ocean Energy Management (the BOEM) and the Bureau of Safety and Environmental Enforcement (the BSEE) (together formerly the Bureau of Ocean Energy Management , Regulation and Enforcement) and other regulatory bodies, including those regulating the decommissioning of our pipelines and facilities under the jurisdiction of the state of Louisiana, may change their requirements or enforce requirements in a manner inconsistent with our expectations, which could materially increase the cost of such activities and/or accelerate the timing of cash expenditures and could have a material adverse effect on our financial position, results of operations and cash flows. For important additional information regarding risks related to our regulatory environment, see Risk Factors in Part II, Item 1A of this Quarterly Report and in Part I, Item 1A of our 2010 Annual Report.

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Analysis of Cash Flows Nine Months Ended September 30, 2011

The following table sets forth our cash flows (in thousands):

	Nine Months Ended September 30, 2011	2010
Cash flows provided by operating activities	$ 105,935	$ 96,992
Cash flows used in investing activities	(244,145)	(31,489)
Cash flows provided by (used in) financing activities	191,925	(62,021)

The increase in our 2011 cash flows from operations primarily reflects increases in revenues due to the increase in oil prices and our oil production, partially offset by decreases in revenues due to the decline in natural gas production. In addition, cash flows from operations reflects increased spending on plugging, abandonment and decommissioning activities during the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010.

Net cash used in investing activities increased in the nine months ended September 30, 2011, as compared to the nine months ended September 30, 2010, primarily as a result of our acquisition of the ASOP Properties during the nine months ended September 30, 2011.

Net cash provided by financing activities during the nine months ended September 30, 2011 reflects $203.8 million of net cash proceeds (before offering expenses of $1.8 million) from the issuance of the 8.25% Notes, partially offset by expenditures of $6.5 million for financing costs primarily associated with our new senior credit facility and the offering expenses associated with our 8.25% Notes and $5.5 million for purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our share repurchase program. Net cash used in financing activities during the nine months ended September 30, 2010 reflects the redemption of the PIK Notes and payments on the term loan component of our prior credit facility, partially offset by proceeds from the term loan component of our prior credit facility.

We have not paid any cash dividends in the past on our common stock. The covenants in certain debt instruments to which we are a party, including our new senior credit facility and the Indenture governing the 8.25% Notes, place certain restrictions and conditions on our ability to pay dividends. Any future cash dividends would depend on contractual limitations, future earnings, capital requirements, our financial condition and other factors determined by our board of directors.

Disclosures about Contractual Obligations and Commercial Commitments

The following table aggregates the contractual commitments and commercial obligations which affect our financial condition and liquidity position as of September 30, 2011.

	Payments Due by Period				
	Total	Three Months Ending December 31, 2011	Two Years Ending December 31, 2013	Two Years Ending December 31, 2015	Thereafter
			(in thousands)		
Indebtedness	$ 210,000	$	$	$	$ 210,000
Interest on indebtedness	112,612		34,650	34,650	43,312
Operating leases	4,865	179	1,715	1,921	1,050
Asset retirement obligations including accretion	237,729	1,590	29,971	27,227	178,941
Total contractual obligations	$ 565,206	$ 1,769	$ 66,336	$ 63,798	$ 433,303

New Accounting Pronouncements

See Note 10 of the condensed consolidated financial statements in Item 1, Part 1 of this Quarterly Report.

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Cautionary Statement Concerning Forward Looking Statements

This Quarterly Report contains forward-looking statements within the meaning of, and we intend that such forward-looking statements be subject to the safe harbor provisions of, the U.S. federal securities laws. Forward-looking statements are, by definition, statements that are not historical in nature and relate to possible future events. They may be, but are not necessarily, identified by words such as will, would, should, likely, estimates, thinks, strives, may, anticipates, expects, believes, intends, goals, plans, or projects and similar expres

These forward-looking statements reflect our current views with respect to possible future events, are based on various assumptions and are subject to risks and uncertainties. These forward-looking statements are not guarantees or predictions of our future performance, and our actual results and future developments may differ materially from those projected in, and contemplated by, the forward-looking statements. As a result, you should not place undue reliance on these forward-looking statements. Our actual results could differ materially from those anticipated in these forward-looking statements. Among the factors that could cause actual results to differ materially are the risks and uncertainties described under Part I, Item 1A, Risk Factors, in our 2010 Annual Report, including the following:

- planned and unplanned capital expenditures;
- adequacy of capital resources and liquidity including, but not limited to, access to additional capacity under our credit facility;
- our substantial level of indebtedness;
- our ability to incur additional indebtedness;
- volatility in oil and natural gas prices;
- volatility in the financial and credit markets;
- changes in general economic conditions;
- uncertainties in reserve and production estimates;
- replacing our oil and natural gas reserves;
- unanticipated recovery or production problems;
- availability, cost and adequacy of insurance coverage;
- hurricane and other weather-related interference with business operations;

- drilling and operating risks;
- production expense estimates;
- the impact of derivative positions;
- our ability to retain and motivate key executives and other necessary personnel;
- availability of drilling and production equipment and field service providers;
- the effects of delays in completion of, or shut-ins of, gas gathering systems, pipelines and processing facilities;
- potential costs associated with complying with new or modified regulations promulgated by the BOEM and BSEE;
- the impact of political and regulatory developments;
- risks and liabilities associated with acquired properties or business;
- our ability to make and integrate acquisitions;
- oil and gas prices and competition; and
- our ability to generate sufficient cash flow to meet our debt service and other obligations.

Many of these factors are beyond our ability to control or predict. Any, or a combination, of these factors could materially affect our future financial condition or results of operations and the ultimate accuracy of the forward-looking statements. These forward-looking statements are not guarantees of our future performance, and our actual results and future developments may differ materially from those projected in the forward-looking statements. Management cautions against putting undue reliance on forward-looking statements or projecting any future results based on such statements.

For a further list and description of various risks, relevant factors and uncertainties that could cause future results or events to differ materially from those expressed or implied in our forward-looking statements, see Risk Factors in Part 1, Item 1A of our 2010 Annual Report and elsewhere in our 2010 Annual Report and elsewhere in this Quarterly Report; our reports and registration statements filed from time to time with the SEC; and other announcements we make from time to time. Given these risks and uncertainties, you should not place undue reliance on these forward-looking statements.

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Although we believe that the assumptions on which any forward-looking statements are based in this Quarterly Report and other periodic reports filed by us are reasonable when and as made, no assurance can be given that such assumptions will prove correct. All forward-looking statements in this Quarterly Report are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report and we undertake no obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws and regulations.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view our ongoing market-risk exposure.

Interest Rate Risk

We are exposed to changes in interest rates which affect the interest earned on our interest-bearing deposits and the interest paid on borrowings under our new senior credit facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At September 30, 2011, our total indebtedness outstanding consisted of $204.2 million (net of unamortized original purchasers discount of $5.8 million) related to our fixed-rate 8.25% Notes. Borrowings under our new credit facility bear interest ranging from a base rate plus a margin of 1.00% to 2.00% on base rate borrowings and LIBOR plus a margin of 2.00% to 3.00% on LIBOR borrowings. We had no amounts drawn under our new credit facility at September 30, 2011.

Commodity Price Risk

Our revenues, profitability and future growth depend substantially on prevailing prices for oil and natural gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we can borrow under our new senior credit facility is subject to periodic redetermination based in part on changing expectations of future prices. Lower prices may reduce the amount of oil and natural gas that we can economically produce. We currently sell all of our oil and natural gas production under price sensitive or market price contracts.

Historically, we have used commodity derivative instruments to manage commodity price risks associated with future oil and natural gas production. As of September 30, 2011, the following derivative instruments were outstanding:

Oil Contracts

	Fixed-Price Swaps				Puts			
Remaining Contract Term	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Average Swap Price ($/Bbl)**	**Fair Value (In thousands)**	**Daily Average Volume (Bbls)**	**Volume (Bbls)**	**Floor Price ($/Bbl)**	**Fair Value (In thousands)**
October 2011 November 2011	2,256	137,600	$ 91.23	$ 1,633	1,301	79,350	$ 60.00	$ 26
December 2011	3,368	104,400	$ 90.25	$ 1,116	1,302	40,350	$ 60.00	$ 57
January 2012 July 2012	2,167	461,500	$ 95.33	$ 6,802				
August 2012 November 2012	721	88,000	$ 95.74	$ 1,187				
December 2012	1,161	36,000	$ 95.28	$ 444				
January 2013 July 2013	1,703	361,000	$ 94.28	$ 3,837				
August 2013 November 2013	426	52,000	$ 94.18	$ 495				
December 2013	806	25,000	$ 93.98	$ 224				

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Remaining Contract Term	Collars Daily Average Volume (Bbls)	Volume (Bbls)	Strike Price ($/Bbl)	Fair Value (In thousands)
January 2012 July 2012	1,000	213,000	$ 87.50/123.18	$ 1,807
August 2012 November 2012	1,000	122,000	$ 87.50/123.18	$ 1,084
December 2012	1,000	31,000	$ 87.50/123.18	$ 276

During October 2011, we entered into the following derivative instruments:

Remaining Contract Term	Fixed-Price Swaps Daily Average Volume (Bbls)	Volume (Bbls)	Strike Price ($/Bbl)
January 2012 May 2012	2,000	304,000	$ 106.90
June 2012 July 2012	1,000	61,000	$ 106.90

Item 4. CONTROLS AND PROCEDURES.

(a) Quarterly Evaluation of Disclosure Controls and Procedures

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in our reports filed under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. This information is also accumulated and communicated to management, including our principal executive officer and our principal financial officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, under the supervision and with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the most recent fiscal quarter reported on herein. Based on that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of September 30, 2011.

Because of their inherent limitations, disclosure controls and procedures may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that such controls and procedures may become inadequate because of changes in conditions, or that the degree of compliance with the controls or procedures may deteriorate. Accordingly, even effective disclosure controls and procedures can provide only reasonable assurance of achieving their control objectives.

(b) Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS.

For information regarding legal proceedings, see the information in Note 9, Commitments and Contingencies in the condensed consolidated financial statements in Part I, Item 1 of this Quarterly Report.

Item 1A. RISK FACTORS.

In addition to the other information set forth in this Form 10-Q, you should carefully consider the factors discussed in Part I, Item 1A. Risk Factors in our 2010 Annual Report that could materially affect our business, financial condition or future results. The risks described in this Form 10-Q and in our 2010 Annual Report are not the only risks facing the Company. Additional risks and uncertainties not currently known to us, or that we currently deem to be immaterial, also may materially adversely affect our business, financial condition and future results.

The risk factor entitled *We may not be insured against all of the operating risks to which our business is exposed* from our 2010 Annual Report is revised to read in its entirety as follows:

We may not be insured against all of the operating risks to which our business is exposed.

In accordance with industry practice, we maintain insurance coverage against some, but not all, of the operating risks to which our business is exposed. We insure some, but not all, of our properties from operational and hurricane related events. We currently have insurance policies that include coverage for general liability, physical damage to our oil and gas properties, operational control of well, oil pollution, third party liability, workers compensation and employers liability and other coverage. Our insurance coverage includes deductibles that must be met prior to recovery, as well as sub-limits. Additionally, our insurance is subject to exclusions and limitations, and there is no assurance that such coverage will adequately protect us against liability from all potential consequences and damages and losses.

Currently, we have general liability insurance coverage with an annual aggregate limit of $2.0 million and umbrella liability coverage with an aggregate limit of $150.0 million applicable to our working interest. Our general liability policy is subject to a $25,000 per incident deductible. We also have an offshore property physical damage policy that contains a $90.0 million annual aggregate named windstorm limit of which we self-insure approximately 9%. This offshore property physical damage policy is subject to a $2.5 million deductible that applies to non-named windstorm occurrences and a $20 million deductible that applies to named windstorm events. Further, there are sub-limits within the named windstorm annual aggregate limit for re-drill, plugging and abandonment and removal of wreck that range from $10 million to $45 million. Our operational control of well coverage provides limits that vary by well location and depth and range from a combined single limit of $20.0 million to $75.0 million per occurrence. Deepwater wells have a coverage limit of $50.0 million per occurrence. Additionally, we maintain $150.0 million in oil pollution liability coverage as required under the Oil Pollution Act of 1990. Our control of well and oil pollution liability policy limits are scaled proportionately to our working interests, except for our deepwater control of well coverage, which limit is to our working interest. Under our service agreements, including drilling contracts, generally we are indemnified for injuries and death of the service provider s employees as well as contractors and subcontractors hired by the service provider.

An operational or hurricane related event may cause damage or liability in excess of our coverage, which might severely impact our financial position. We may be liable for damages from an event relating to a project in which we are a non-operator, but have a working interest in such project. Such an event may also cause a significant interruption to our business, which might also severely impact our financial position. For example, we experienced production interruptions in 2005, 2006 and 2007 from Hurricanes Katrina and Rita and in 2008 and 2009 from Hurricanes Gustav and Ike for which we had no production interruption insurance.

We reevaluate the purchase of insurance, policy limits and terms annually each April. In light of the catastrophic Deepwater Horizon accident in the Gulf of Mexico in April 2010, we may not be able to secure similar coverage for the same costs. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations in the Gulf of Mexico, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

We maintain an Oil Spill Response Plan (the Plan) that defines our response requirements and procedures and remediation plans in the event we have an oil spill. Oil Spill Response Plans are generally approved by the BSEE bi-annually, except when changes are required, in which case revised plans are required to be submitted for approval at the time changes are made. We believe the Plan specifications are consistent with the requirements set forth by the BSEE.

The Company has contracted with an emergency and spill response management consultant, which would provide management expertise, personnel and equipment, under the supervision of the Company, in the event of an incident requiring a coordinated response. Additionally, the Company is a member of Clean Gulf Associates (CGA), a not-for-profit association of producing and pipeline companies operating in the Gulf of Mexico and has capabilities to simultaneously respond to multiple spills. CGA s website states that it is the largest oil spill response cooperative in North America. CGA is structured to provide an effective method of staging response equipment and providing spill response for its member companies in the Gulf of Mexico. CGA has chartered its marine equipment to the Marine Spill Response Corporation (MSRC), a private, not-for-profit marine spill response organization which is funded by the Marine Preservation Association (MPA), a member-supported, not-for-profit organization created to assist the petroleum and energy-related industries by addressing problems caused by oil spills on water. MSRC s website states that it is the largest dedicated oil spill response organization in the United States. MSRC owns and operates a fleet of dedicated Oil Spill Response Vessels (OSRV), ocean-going barges, shallow water skimming systems, other response equipment and enhanced communications capabilities in various regions including the Gulf of Mexico. MSRC maintains CGA s equipment (currently including, according to CGA s website, 11 skimming vessels with capacities ranging from 3,000 to 43,000 barrels per day, 17 skimmers with capacities up to 3,770 barrels per day, numerous containment and storage systems including thousands of feet of boom and two fire boom systems, tanks and storage barges, wildlife cleaning and rehabilitation facilities, both aerial and vessel dispersant spray systems and 33,300 gallons of dispersant) at staging points around the Gulf of Mexico in its ready state. In the event of a spill, MSRC mobilizes appropriate equipment to CGA members. In addition, CGA maintains a contract with Airborne Support Inc., which provides aircraft and dispersant capabilities for CGA member companies.

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Additional resources are available to the Company on an as-needed basis other than as a member of CGA, such as those of MSRC. MSRC has oil spill response equipment independent of, and in addition to, CGA s equipment. MSRC s capabilities are augmented by a network of over 100 participants in the Spill Team Area Responders (STARs) program, an affiliation of environmental response contractors located at over 200 locations throughout the country. MSRC s equipment currently includes, according to MSRC s website, 15 oil spill response vessels (in the Gulf of Mexico) with temporary storage for 4,000 barrels of oil and the ability to separate oil and water, 19 oil spill response barges with storage capacities between 12,000 and 68,000 barrels, 68 shallow water barges, 600,000 feet of boom, over 240 skimming systems, six self-propelled skimming vessels, seven mobile communication suites comprising telephone and computer connections and marine, aviation and business band radios, various small crafts and shallow water vessels and two dispersant/spotter aircraft. In the event of a spill, MSRC activates contractors as necessary to provide additional resources or support services requested by its customers.

The response effectiveness, equipment and resources of these companies may change from time-to-time and current information is generally available on the websites of each of these organizations. There can be no assurances that the Company, together with the organizations described above will be able to effectively manage all emergency and/or spill response activities that may arise and any failures to do so may materially adversely impact the Company s financial position, results of operations and cash flows.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs (1) (in thousands)
September 2011	590,000	$ 11.88	590,000	$ 12,992

(1) On August 29, 2011, we announced that the Board of Directors authorized a program for the repurchase of shares of our outstanding common stock for up to an aggregate cash purchase price of $20.0 million. We are funding the stock repurchases out of cash on hand. The repurchased shares will be accumulated and held in treasury. The repurchases are carried out in accordance with certain volume, timing and price constraints imposed by the SEC s rules applicable to such transactions. The amount, timing and price of purchases otherwise depend on market conditions and other factors.

Item 3. DEFAULTS UPON SENIOR SECURITIES.

None

Item 5. OTHER INFORMATION.

None

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Item 6. EXHIBITS.

The exhibits marked with the cross symbol ( ) are management contracts or compensatory plans or arrangements filed pursuant to Item 601(b)(10)(iii) of Regulation S-K. We have not filed with this Quarterly Report copies of the instruments defining rights of all holders of the long-term debt of us and our consolidated subsidiaries based upon the exception set forth in Item 601(b)(4)(iii)(A) of Regulation S-K. Copies of such instruments will be furnished to the SEC upon request.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
2.0	Second Amended Joint Plan of Reorganization of Energy Partners, Ltd. and certain of its Subsidiaries Under Chapter 11 of the Bankruptcy Code, as Modified as of September 16, 2009	10-Q	001-16179	2.0	05/06/2010	
2.1	Purchase and Sale Agreement dated January 13, 2011, by and between Anglo-Suisse Offshore Partners, LLC and Energy Partners, Ltd.	8-K	001-16179	2.1	01/18/2011	
3.1	Amended and Restated Certificate of Incorporation of Energy Partners, Ltd. dated as of September 21, 2009	8-A/A	001-16179	3.1	09/21/2009	
3.2	Second Amended and Restated Bylaws of Energy Partners, Ltd.	8-A/A	001-16179	3.2	09/21/2009	
4.1	Indenture by and among Energy Partners, Ltd., as Issuer, the Guarantors named therein and U.S. Bank National Association, as Trustee dated February 14, 2011	8-K	001-16179	4.1	02/15/2011	
4.2	Supplemental Indenture by and among Anglo-Suisse Offshore Pipeline Partners, LLC, as a Guarantor, Energy Partners, Ltd., as Issuer, and the other Guarantors named therein and U.S. Bank National Association, as Trustee, dated March 14, 2011	S-4	333-175567	4.2	07/14/2011	
31.1	Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Section 1350 Certification of Principal Executive Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Section 1350 Certification of Principal Financial Officer of Energy Partners, Ltd. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
101.INS*	XBRL Instance Document					X
101.SCH*	XBRL Taxonomy Extension Schema Document					X
101.CAL*						X

	XBRL Taxonomy Extension Calculation Linkbase Document	
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document	X
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document	X

* In accordance with Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q is furnished and shall not be deemed to be filed for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be part of any registration statement or other document filed under the Securities Act or the Exchange Act, except as shall be expressly set forth by specific reference in such filing.

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SIGNATURE

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.

ENERGY PARTNERS, LTD.

Date: November 3, 2011	By: /s/ Tiffany J. Thom Tiffany J. Thom Senior Vice President and Chief Financial Officer (Principal Financial Officer)

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