EPL OIL & GAS, INC.
Form 10-Q
October 31, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

OR

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

Commission File Number: 001-16179

EPL Oil & Gas, Inc.

(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 No.)
919 Milam Street, Suite 1600, Houston, Texas	77002

(Address of principal executive offices) (Zip code)

(713) 228-0711

(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 October 25, 2013, there were 39,083,424 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.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

(In thousands, except share data)

	September 30, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 2,939	$ 1,521
Trade accounts receivable - net	68,748	67,991
Fair value of commodity derivative instruments	972	3,302
Deferred tax asset	4,414	3,322
Prepaid expenses	14,454	9,873
Total current assets	91,527	86,009
Property and equipment, at cost, under the successful efforts method of accounting	2,299,323	2,025,647
Less accumulated depreciation, depletion, amortization and impairments	(569,124)	(427,580)
Net property and equipment	1,730,199	1,598,067
Restricted cash	6,023	6,023
Fair value of commodity derivative instruments	675	211
Deferred financing costs -- net of accumulated amortization of $4,800 at September 30, 2013 and $2,596 at December 31, 2012	10,851	12,386
Other assets	4,023	2,931
Total assets	$ 1,843,298	$ 1,705,627
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 55,410	$ 34,772
Accrued expenses	103,160	117,372
Asset retirement obligations	47,482	30,179
Fair value of commodity derivative instruments	10,694	10,026
Total current liabilities	216,746	192,349
Long-term debt	621,723	689,911
Asset retirement obligations	240,288	204,931
Deferred tax liabilities	124,025	67,694
Fair value of commodity derivative instruments	281	3,637
Other	1,158	1,132
Total liabilities	1,204,221	1,159,654
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.001 par value. Authorized 1,000,000 shares; no shares issued and outstanding	-	-

at September 30, 2013 and December 31, 2012		
Common stock, par value $0.001 per share. Authorized 75,000,000 shares; shares issued: 40,948,737 and 40,601,887 at September 30, 2013 and December 31, 2012, respectively; shares outstanding: 39,083,424 and 39,103,203 at September 30, 2013 and December 31, 2012, respectively	40	40
Additional paid-in capital	516,690	510,469
Treasury stock, at cost, 1,865,313 and 1,498,684 shares at September 30, 2013 and December 31, 2012, respectively	(30,926)	(20,477)
Retained earnings	153,273	55,941
Total stockholders’ equity	639,077	545,973
Total liabilities and stockholders' equity	$ 1,843,298	$ 1,705,627

See accompanying notes to condensed consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(UNAUDITED)

(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenue:				
Oil and natural gas	$ 183,114	$ 86,645	$ 547,099	$ 284,666
Other	878	23	3,329	68
Total revenue	183,992	86,668	550,428	284,734
Costs and expenses:				
Lease operating	42,291	24,995	126,663	62,067
Transportation	974	160	2,317	410
Exploration expenditures and dry hole costs	5,146	966	13,609	17,862
Impairments	12	498	2,183	6,206
Depreciation, depletion and amortization	53,989	27,106	153,847	78,932
Accretion of liability for asset retirement obligations	6,266	3,472	18,464	10,031
General and administrative	6,426	5,995	20,927	16,993
Taxes, other than on earnings	3,285	3,189	8,884	9,834
Gain on sale of assets	(1,745)	-	(28,601)	-
Other	26,534	998	33,077	4,616
Total costs and expenses	143,178	67,379	351,370	206,951
Income from operations	40,814	19,289	199,058	77,783
Other income (expense):				
Interest income	64	40	91	128
Interest expense	(13,177)	(5,114)	(39,370)	(15,081)
Loss on derivative instruments	(30,012)	(22,108)	(7,033)	(11,865)
Total other income (expense)	(43,125)	(27,182)	(46,312)	(26,818)
Income (loss) before income taxes	(2,311)	(7,893)	152,746	50,965
Provision for income taxes:				
Current	(25)	126	(175)	(174)
Deferred	1,052	5,520	(55,239)	(16,134)
Total provision for income taxes	1,027	5,646	(55,414)	(16,308)
Net income (loss)	(1,284)	(2,247)	97,332	34,657
Basic earnings (loss) per share	$ (0.03)	$ (0.06)	$ 2.48	$ 0.88
Diluted earnings (loss) per share	$ (0.03)	$ (0.06)	$ 2.45	$ 0.88
Weighted average common shares used in computing earnings per share:				
Basic	38,589	38,743	38,760	38,926
Diluted	38,589	38,743	39,256	39,056

See accompanying notes to condensed consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

(In thousands)

	Nine Months Ended September 2013		2012	
Cash flows from operating activities:				
Net income	$	97,332	$	34,657
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, depletion and amortization		153,847		78,932
Accretion of liability for asset retirement obligations		18,464		10,031
Unrealized loss (gain) on derivative contracts		(822)		8,052
Non-cash compensation		5,358		3,493
Deferred income taxes		55,239		16,134
Exploration expenditures		3,764		4,097
Impairments		2,183		6,206
Amortization of deferred financing costs and discount on debt		4,016		1,516
Gain on sale of assets		(28,601)		-
Other		27,982		3,405
Changes in operating assets and liabilities:				
Trade accounts receivable		(1,718)		5,171
Prepaid expenses		(5,308)		4,062
Other assets		(1,077)		362
Accounts payable and accrued expenses		15,345		14,149
Asset retirement obligation settlements		(36,843)		(27,647)
Net cash provided by operating activities		309,161		162,620
Cash flows provided by (used in) investing activities:				

Property acquisitions		(26,979)		(34,458)
Deposit for Hilcorp Acquisition		-		(55,000)
Exploration and development expenditures		(252,125)		(135,950)
Other property and equipment additions		(1,517)		(1,474)
Proceeds from sale of assets		52,237		-
Net cash used in investing activities		(228,384)		(226,882)
Cash flows provided by (used in) financing activities:				
Repayment of indebtedness		(70,000)		-
Deferred financing costs		(670)		(6)
Purchase of shares into treasury		(9,640)		(8,798)
Exercise of stock options		951		257
Net cash used in financing activities		(79,359)		(8,547)
Net increase (decrease) in cash and cash equivalents		1,418		(72,809)
Cash and cash equivalents at beginning of period		1,521		80,128
Cash and cash equivalents at end of period	$	2,939	$	7,319

See accompanying notes to condensed consolidated financial statements.

EPL OIL & GAS, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

(1) Basis of Presentation

EPL Oil & Gas, Inc. ("we," "our," "us," or "the Company") was incorporated as a Delaware corporation on January 29, 1998. We are 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.

The financial information as of September 30, 2013 and for the three- and nine-month periods ended September 30, 2013 and September 30, 2012 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 in accordance with rules and regulations of the Securities and Exchange Commission. The condensed consolidated balance sheet at December 31, 2012 has been derived from the audited financial statements at that date. 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, 2012 (the "2012 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 and Dispositions

The Hilcorp Acquisition

On October 31, 2012, we acquired from Hilcorp Energy GOM Holdings, LLC ("Hilcorp") 100% of the membership interests of Hilcorp Energy GOM, LLC (the "Hilcorp Acquisition"), which owned certain shallow water Gulf of Mexico shelf oil and natural gas interests (the "Hilcorp Properties"), for $550 million in cash, subject to customary adjustments to reflect an economic effective date of July 1, 2012. As of December 31, 2012, the Hilcorp Properties had estimated proved reserves of approximately 37.2 Mmboe, of which 49% were oil and 58% were proved developed reserves. The primary factors considered by management in acquiring the Hilcorp Properties include the belief that the Hilcorp Acquisition provided 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 on the Gulf of Mexico shelf. The Hilcorp Acquisition also provided us with access to infrastructure and extensive acreage, with significant exploitation and development potential.

The Hilcorp Acquisition was financed with cash on hand, the net proceeds from the sale of $300.0 million in aggregate principal amount of 8.25% senior notes due 2018 ("the 2012 Senior Notes") and borrowings under our expanded senior credit facility. See Note 5, "Indebtedness," for more information regarding our 2012 Senior Notes.

The following allocation of the purchase price is preliminary and includes estimates. This preliminary allocation is based on information that was available to management at the time these condensed consolidated financial statements were prepared and takes into account current market conditions and estimated market prices for oil and natural gas. Management has not yet had the opportunity to complete its assessment of fair values of the assets acquired and liabilities assumed. Accordingly, the allocation may change materially as additional information becomes available and is assessed by management.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects management's estimate of customary adjustments to purchase price provided for by the purchase and sale agreement of approximately $6.2 million to reflect an economic effective date of July 1, 2012.

(In thousands)	
Oil and natural gas properties	$ 684,900
Asset retirement obligations	(137,774)
Net assets acquired	$ 547,126

Sale of Non-Operated Bay Marchand Asset

On April 2, 2013, we sold certain shallow water Gulf of Mexico shelf oil and natural gas interests located within the non-operated Bay Marchand field (the "BM Interests") to the property operator for $51.5 million in cash and the buyer's assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. Our results for the nine months ended September 30, 2013 reflect a pre-tax gain of $28.1 million from this sale. The following table summarizes the carrying amount of the net assets sold and reflects management's estimates of customary adjustments to the sale price of approximately $0.7 million to reflect the economic effective date of January 1, 2013.

(In thousands)	
Net property and equipment	$ 35,298
Asset retirement obligations	(3,959)
Other liabilities	(7,311)
Net assets sold	$ 24,028

The cash proceeds from this sale of assets were held on deposit with a qualified intermediary in contemplation of a potential tax-deferred exchange of properties and classified as restricted cash at June 30, 2013. On September 26, 2013, we used $16.5 million of these proceeds to fund the WD29 Acquisition (defined and described below), which was a qualifying purchase for tax-deferral purposes. On September 29, 2013, the underlying escrow agreement expired, and the remaining amount of the deposit became unrestricted.

The West Delta 29 Acquisition

On September 26, 2013, we acquired from W&T Offshore, Inc. ("W&T") an asset package consisting of certain Gulf of Mexico shelf oil and natural gas interests in the West Delta 29 field (the "WD29 Interests") for $21.8 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2013 (the "WD29 Acquisition"). We estimate that the proved reserves as of the January 1, 2013 economic effective date totaled approximately 0.6 Mmboe, of which 90% were oil and 94% were proved developed reserves. The WD29 Acquisition was funded with a portion of the proceeds from the sale of the BM Interests held by the qualified intermediary as described above.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects management's estimate of customary adjustments to purchase price provided for by the purchase and sale agreement of approximately $4.7 million to reflect an economic effective date of January 1, 2013.

(In thousands)	
Oil and natural gas properties	$ 18,458
Asset retirement obligations	(1,398)
Net assets acquired	$ 17,060

The South Timbalier Acquisition

On May 15, 2012, we acquired from W&T an asset package consisting of certain shallow-water Gulf of Mexico shelf oil and natural gas interests in our South Timbalier 41 field (the "ST41 Interests") located in the Gulf of Mexico for $32.4 million in cash, subject to customary adjustments to reflect an economic effective date of April 1, 2012 (the "ST41 Acquisition"). We estimate that the proved reserves as of the April 1, 2012 economic effective date totaled approximately 1.0 Mmboe, of which 51% were oil and 84% were proved developed reserves. Prior to the ST41 Acquisition, we owned a 60% working interest in these properties, and W&T owned a 40% working interest. As a result of the ST41 Acquisition, we became the sole working interest owner of the South Timbalier 41 field. We funded the ST41 Acquisition with cash on hand.

The following table summarizes the estimated values of assets acquired and liabilities assumed and reflects final adjustments to purchase price provided for by the purchase and sale agreement of approximately $0.4 million to reflect an economic effective date of April 1, 2012.

(In thousands)		
Oil and natural gas properties	$	33,206
Asset retirement obligations		(1,878)
Net assets acquired	$	31,328

We have accounted for our acquisitions using the purchase method of accounting for business combinations, and therefore we have estimated the fair value of the assets acquired and the liabilities assumed as of their respective acquisition dates. In the estimation of fair value, management uses various valuation methods including (i) comparable company analysis, which estimates the value of the acquired 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. 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 7, "Fair Value Measurements."

Results of Operations and Pro Forma Information

The following table sets forth revenues and lease operating expenses attributable to the Hilcorp Properties and the ST41 Interests.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Hilcorp Properties:				
Revenue	$ 53,769	$ -	157,439	-
Lease operating expenses	$ 19,896	$ -	59,027	-
ST41 Interests:				
Revenue	$ 2,816	$ 3,559	$ 8,746	$ 5,496
Lease operating expenses	$ 539	$ 709	$ 1,573	$ 1,001

We have determined that the presentation of net income attributable to the Hilcorp Properties and the ST41 Interests is impracticable due to the integration of the related operations upon acquisition.

The following supplemental pro forma information presents consolidated results of operations as if the Hilcorp Acquisition and the ST41 Acquisition had occurred on January 1, 2011. The supplemental unaudited pro forma information was derived from a) our historical consolidated statements of operations, b) the statements of operations of Hilcorp Energy GOM, LLC and c) the statements of revenues and direct operating expenses for the ST41 Interests, which were derived from our historical accounting records. This information does not purport to be indicative of results of operations that would have occurred had the acquisitions occurred on January 1, 2011, nor is such information indicative of any expected future results of operations.

	Pro Forma Three Months Ended September 30, 2012	Pro Forma Nine Months Ended September 30, 2012
	(in thousands, except for share data)	
Revenue	$ 136,324	$ 437,026
Net income (loss)	$ (9,379)	$ 32,949
Basic earnings (loss) per share	$ (0.24)	$ 0.84
Diluted earnings (loss) per share	$ (0.24)	$ 0.84

(3) Earnings per Share

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands, except for share data)			
Income (numerator):				
Net income (loss)	$ (1,284)	$ (2,247)	$ 97,332	$ 34,657
Net income attributable to participating securities	-	-	(1,059)	(260)
Net income (loss) attributable to common shares	$ (1,284)	$ (2,247)	$ 96,273	$ 34,397
Weighted average shares (denominator):				
Weighted average shares—basic	38,589	38,743	38,760	38,926
Dilutive effect of stock options	-	-	496	130
Weighted average shares—diluted	38,589	38,743	39,256	39,056
Basic earnings (loss) per share	$ (0.03)	$ (0.06)	$ 2.48	$ 0.88
Diluted earnings (loss) per share	$ (0.03)	$ (0.06)	$ 2.45	$ 0.88

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The following table indicates the number of shares underlying outstanding stock-based awards excluded from the computation of dilutive weighted average shares because their effect was antidilutive for the periods indicated.

(in thousands)	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
Weighted average shares	1,037	905	247	653

(4) Asset Retirement Obligations

The following table reconciles the beginning and ending aggregate recorded amount of our asset retirement obligations.

	Nine Months Ended September 30, 2013 (in thousands)
Balance at December 31, 2012	$ 235,110
Accretion expense	18,464
Liabilities assumed in acquisitions	10,355
Liabilities incurred	1,187
Revisions	63,462
Liabilities associated with assets sold	(3,965)
Liabilities settled	(36,843)
Balance at September 30, 2013	287,770
Less: End of period, current portion	47,482
End of period, noncurrent portion	$ 240,288

During the three months ended September 30, 2013, we recorded a revision to our estimated asset retirement obligations (“ARO”) of $21.8 million related to our only remaining four non-producing wellbores in our non-operated deepwater properties. These increased deepwater abandonment costs are primarily attributable to changes in regulatory interpretations and enforcement by the Bureau of Safety and Environmental Enforcement in the deepwater that increased the required scope of work. As a result, we recorded an associated $21.8 million loss on abandonment activities, which is included in Other costs and expenses in our condensed consolidated statements of operations for the three and nine months ended September 30, 2013.

We revise our estimates of ARO as information about material changes to the liability becomes known. During the three months ended September 30, 2013, we recorded revisions to our ARO liability related to our shallower-water assets of $31.0 million. This does not affect current results of operations, but increases the carrying amount of our assets and will result in higher depreciation, depletion and amortization and accretion expense in future periods.

(5) Indebtedness

The following table sets forth our indebtedness.

	September 30, 2013 (In thousands)		December 31, 2012	
8.25% Senior Notes, face amount of $510.0 million, interest rate of 8.25% payable semi-annually, in arrears on February 15 and August 15 of each year, maturity date February 15, 2018	$	496,723	$	494,911
Senior credit facility, interest rate based on base rate or LIBOR plus a floating spread, maturity date October 31, 2016		125,000		195,000
Total indebtedness		621,723		689,911
Current portion of indebtedness		-		-
Noncurrent portion of indebtedness	$	621,723	$	689,911

8.25% Senior Notes

The 8.25% senior notes consist of $510.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the “8.25% Senior Notes”) issued under an Indenture dated February 14, 2011 (the “2011 Indenture”). The 8.25% Senior

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 15th and August 15th of each year. The 8.25% Senior 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% Senior Notes will mature on February 15, 2018. The effective interest rate on the 8.25% Senior Notes is approximately 9.1%. We issued the 8.25% Senior Notes in two different private placements, described below.

On February 14, 2011, we issued $210.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the "2011 Senior Notes") under an Indenture dated as of February 14, 2011 (the "2011 Indenture"). We used the net proceeds from the offering of the 2011 Senior Notes of $202.0 million, after deducting the initial purchasers' discount and offering expenses payable by us, to acquire 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 from Anglo-Suisse Offshore Partners, LLC ("ASOP") for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011 (the "ASOP Acquisition"). For additional information regarding the 2011 Senior Notes, see Note 7, "Indebtedness," of our 2012 Annual Report.

On October 25, 2012, we issued $300.0 million in aggregate principal amount of our 2012 Senior Notes under an Indenture dated as of October 25, 2012 (the "2012 Indenture"). As described in Note 2, "Acquisitions," we used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers' discount, to fund a portion of the Hilcorp Acquisition. The purchase price of the 2012 Senior Notes included $4.8 million of accrued interest for the period from August 15, 2012 to October 25, 2012, which we recorded as interest payable.

The 2012 Senior Notes 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. The 2012 Senior Notes had terms that were substantially identical to the terms of our 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the 2012 Senior Notes (the "Registration Rights Agreement"), we have issued publicly registered additional notes under our 2011 Indenture in exchange for the 2012 Senior Notes. As a result of this exchange offer, 100% in aggregate principal amount of the 2012 Senior Notes was exchanged for the notes under the 2011 Indenture, effective as of June 10, 2013. All of the 8.25% Senior Notes are now issued under the 2011 Indenture, regardless of which private placement they were issued under. For more information regarding the 2012 Senior Notes, see Note 7, "Indebtedness," of our 2012 Annual Report.

Senior Credit Facility

On February 14, 2011, we entered into our senior secured credit facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto (as amended and restated, the "Senior Credit Facility"). The original terms of our Senior Credit Facility established a revolving credit facility with a four-year term that could be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million. On October 31, 2012, in connection with the Hilcorp Acquisition, through an amendment and restatement of our Senior Credit Facility, the aggregate commitment under this facility was increased to a maximum of $750.0 million and the maturity date was extended to October 31, 2016. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million. The amount available under the revolving credit facility is limited by the borrowing base. The borrowing base under our Senior 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. On October 31, 2012, the borrowing base was increased from $200.0 million to $425.0 million. We are currently in the process of our semi-annual redetermination. Our borrowing base remains at $425.0 million until redetermined. In addition, in July 2013, our Senior Credit Facility was amended to increase the limit applicable to certain restricted payments permitted by the agreement to accommodate our expanded stock repurchase program. As of September 30, 2013 and December 31, 2012, we had outstanding under the Senior Credit Facility $125.0 million and $195.0 million, respectively. For additional information regarding our Senior Credit Facility, see Note 7, “Indebtedness,” of our 2012 Annual Report.

(6) Derivative Instruments and Hedging Activities

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 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 instruments 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. See Note 7 for information regarding fair values of our derivative instruments.

The following table sets forth our derivative instruments outstanding as of September 30, 2013.

Oil Contracts

	Fixed-Price Swaps		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
October 2013	5,719	177,300	103.94
November 2013	6,233	187,000	103.93
December 2013	9,156	283,850	103.24
2013 Total	7,045	648,150	103.63
January 2014	14,350	444,850	100.00
February 2014	14,350	401,800	100.00
March 2014	14,350	444,850	100.00
April 2014	13,350	400,500	99.83
May 2014	13,350	413,850	99.83
June 2014	13,350	400,500	99.83
July 2014	12,350	382,850	99.46
August 2014	6,750	209,250	98.83
September 2014	6,750	202,500	98.83
October 2014	6,750	209,250	98.83
November 2014	6,750	202,500	98.83
December 2014	9,700	300,700	98.52
2014 Total	10,996	4,013,400	99.54
January 2015 - December 2015	1,500	547,500	97.70

	Collars		
Remaining Contract Term	Daily Average Volume (Bbls)	Volume (Bbls)	Average Swap Price ($/Bbl)
October 2013—December 2013	1,000	92,000	$ 80.00/104.10

Gas Contracts

	Fixed-Price Swaps		
Remaining Contract Term	Daily Average Volume (Mmbtu)	Volume (Mmbtu)	Average Swap Price ($/Mmbtu)
October 2013	8,000	248,000	3.58
November 2013	7,500	225,000	3.67
December 2013	6,500	201,500	3.83
2013 Total	7,332	674,500	3.68
January 2014 - December 2014	5,000	1,825,000	4.01
January 2015 - December 2015	4,300	1,569,500	4.31

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Derivative contracts:				
Unrealized gain (loss) due to change in fair value	$ (26,478)	$ (22,010)	$ 822	$ (8,052)
Realized loss on settlement	(3,534)	(98)	(7,855)	(3,813)
Total loss on derivative instruments	$ (30,012)	$ (22,108)	$ (7,033)	$ (11,865)

(7) Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting Standards Codification ("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, 2013 and December 31, 2012, 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 our derivative instruments were measured according to the market approach or, if necessary, the income approach using price inputs published by NYMEX and IntercontinentalExchange, Inc., or ICE. These price inputs include settled exchange prices and 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.

In December 2011, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities" ("ASU 2011-11"). ASU 2011-11 requires disclosure of information about offsetting and related arrangements to enable users of financial statements to understand the effect or potential effect of netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. In January 2013, the FASB issued ASU No. 2013-01, "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities," to clarify that ASU 2011-11 applies to derivatives, repurchase agreements and securities lending transactions. Our commodity derivative instruments are subject to the terms of agreements with each of our counterparties that provide for the liquidation and settlement of all transactions with that counterparty in the event of default or termination. Our counterparties under these agreements are participants in our Senior Credit Facility. Although our derivative instruments are subject to enforceable set-off arrangements, we do not elect to offset amounts reported in our condensed consolidated balance sheet.

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The following table presents the fair values of our commodity derivative instruments at their gross amounts and reflects the impact of our set-off arrangements which qualify for net presentation.

	September 30, 2013	December 31, 2012
Fair value of commodity derivative instruments:	(in thousands)	
Assets:		
Current	$ 972	$ 3,302
Noncurrent	675	211
Total gross fair value	1,647	3,513
Less: counterparty set-off	(1,647)	(3,513)
Total net fair value	-	-
Liabilities:		
Current	$ 10,694	$ 10,026
Noncurrent	281	3,637
Total gross fair value	10,975	13,663
Less: counterparty set-off	(1,647)	(3,513)
Total net fair value	9,328	10,150

The carrying values reported in the condensed consolidated balance sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value due to the short term maturities of these instruments. The fair value of the 8.25% Senior Notes is based on quoted prices, which are Level 1 inputs within the fair value hierarchy. The carrying value of the Senior Credit Facility approximates its fair value because the interest rates are variable and reflective of market rates, which are Level 2 inputs within the fair value hierarchy.

The following table sets forth the carrying values and estimated fair values of our long-term indebtedness.

	September 30, 2013		December 31, 2012	
	(In thousands)			
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
8.25% Senior Notes	$ 496,723	$ 539,325	$ 494,911	$ 524,600
Senior Credit Facility	125,000	125,000	195,000	195,000
Total	$ 621,723	$ 664,325	$ 689,911	$ 719,600

Effective June 1, 2013, we entered into agreements with a group of capital market participants (the “Counterparties”) whereby if a named wind storm occurs in a specified area of the Gulf of Mexico and that storm meets certain strength criteria and one or more scheduled assets within that specified area are deemed totally destroyed, then the Counterparties will pay to us a fixed amount of cash proceeds specific for each such destroyed asset. These agreements are financial instruments and are considered weather derivatives under the applicable authoritative guidance related to financial instruments. We recognized the premiums paid as current assets, which we are amortizing to expense over the terms of the agreements. At September 30, 2013, we estimate that the fair value of these financial instruments approximates the carrying amount of approximately $2.7 million, based on the amount of premiums paid, which is a Level 3 input 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, which is 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 are based on our estimates of future events, including projections of future oil and natural gas sales prices, amounts of recoverable oil and natural gas reserves, timing of future production, future costs to develop and produce our oil and natural gas and discount factors. These inputs meet the definition of Level 3 inputs within the fair value hierarchy. Impairments for the nine months ended September 30, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. We determined this field had future net cash flows less than its carrying value resulting in the write down of this property to its estimated fair value at September 30, 2013. Impairments for the nine months ended September 30, 2012 were primarily due to the decline in our estimate of future natural gas prices affecting certain of our natural gas producing fields and to reservoir performance of one of our natural gas producing fields.

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

(8) 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 over time 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, 2013, 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.

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. We had previously recorded as a liability an amount that we believed may have been payable related to a potential reallocation, which amount was reflected in the accompanying condensed consolidated balance sheets in Accrued expenses as of December 31, 2012. As part of the consideration for its purchase of the BM Interests, the buyer assumed any amounts due related to this matter and we removed the liability from our balance sheet. See Note 2, “Acquisitions and Dispositions-Sale of Non-Operated Bay Marchand Asset” for more information.

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.

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.

(9) Supplemental Condensed Consolidating Financial Information

In connection with issuing the 8.25% Senior Notes described in Note 5, all of our existing direct and indirect domestic subsidiaries (other than immaterial subsidiaries) (the “Guarantor Subsidiaries”) jointly and severally guaranteed the payment obligations under our 8.25% Senior Notes. The guarantees are full and unconditional, as those terms are used in Rule 3-10 of Regulation S-X, except that a Guarantor Subsidiary can be automatically released and relieved of its obligations under certain customary circumstances contained in the indenture governing the 8.25% Senior Notes. So long as other applicable provisions of the indenture are adhered to, these customary circumstances include: when a Guarantor Subsidiary is declared “unrestricted” for covenant purposes, when the requirements for legal defeasance or covenant defeasance or to discharge the indenture have been satisfied, or when the Guarantor Subsidiary is sold or sells all of its assets. The following supplemental financial information sets forth, on a consolidating basis, the balance sheets, statements of operations and cash flow information for EPL Oil & Gas, Inc. (Parent Company Only) and for the Guarantor Subsidiaries. We have not presented separate financial statements and other disclosures concerning the Guarantor Subsidiaries, or for any individual Guarantor Subsidiary, 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.

Supplemental Condensed Consolidating Balance Sheet

As of September 30, 2013

	Parent Company Only (In thousands)	Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS				
Current assets:				
Cash and cash equivalents	$ 2,939	$ -	$ -	$ 2,939
Trade accounts receivable - net	68,618	130	-	68,748
Intercompany receivables	44,311	-	(44,311)	-
Fair value of commodity derivative instruments	972	-	-	972
Deferred tax asset	4,414	-	-	4,414
Prepaid expenses	14,454	-	-	14,454
Total current assets	135,708	130	(44,311)	91,527
Property and equipment	1,984,800	314,523	-	2,299,323
Less accumulated depreciation, depletion, amortization and impairments	(482,937)	(86,187)	-	(569,124)
Net property and equipment	1,501,863	228,336	-	1,730,199
Investment in affiliates	120,943	-	(120,943)	-
Restricted cash	6,023	-	-	6,023
Fair value of commodity derivative instruments	675	-	-	675
Deferred financing costs	10,851	-	-	10,851
Other assets	3,933	90	-	4,023
Total assets	$ 1,779,996	$ 228,556	$ (165,254)	$ 1,843,298
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Accounts payable	$ 54,590	$ 820	$ -	$ 55,410
Intercompany payables	-	44,311	(44,311)	-
Accrued expenses	103,144	16	-	103,160
Asset retirement obligations	42,491	4,991	-	47,482
Fair value of commodity derivative instruments	10,694	-	-	10,694
Total current liabilities	210,919	50,138	(44,311)	216,746
Long-term debt	621,723	-	-	621,723
Asset retirement obligations	198,936	41,352	-	240,288
Deferred tax liabilities	107,902	16,123	-	124,025
Fair value of commodity derivative instruments	281	-	-	281
Other	1,158	-	-	1,158
Total liabilities	1,140,919	107,613	(44,311)	1,204,221
Stockholders' equity:				
Preferred stock	-	-	-	-
Common stock	40	-	-	40
Additional paid-in capital	516,690	85,479	(85,479)	516,690
Treasury stock, at cost	(30,926)	-	-	(30,926)
Retained earnings	153,273	35,464	(35,464)	153,273
Total stockholders' equity	639,077	120,943	(120,943)	639,077

Total liabilities and stockholders' equity	$ 1,779,996	$ 228,556	$ (165,254)	$ 1,843,298

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Supplemental Condensed Consolidating Balance Sheet

As of December 31, 2012

	Parent Company Only (In thousands)	Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS				
Current assets:				
Cash and cash equivalents	$ 1,521	$ -	$ -	$ 1,521
Trade accounts receivable - net	66,994	997	-	67,991
Intercompany receivables	55,575	-	(55,575)	-
Fair value of commodity derivative instruments	3,302	-	-	3,302
Deferred tax asset	3,322	-	-	3,322
Prepaid expenses	9,873	-	-	9,873
Total current assets	140,587	997	(55,575)	86,009
Property and equipment	1,754,294	271,353	-	2,025,647
Less accumulated depreciation, depletion, amortization and impairments	(353,526)	(74,054)	-	(427,580)
Net property and equipment	1,400,768	197,299	-	1,598,067
Investment in affiliates	111,191	-	(111,191)	-
Restricted cash	6,023	-	-	6,023
Fair value of commodity derivative instruments	211	-	-	211
Deferred financing costs	12,386	-	-	12,386
Other assets	2,841	90	-	2,931
Total assets	$ 1,674,007	$ 198,386	$ (166,766)	$ 1,705,627
LIABILITIES AND STOCKHOLDERS’ EQUITY				
Current liabilities:				
Accounts payable	$ 34,740	$ 32	$ -	$ 34,772
Intercompany payables	-	55,575	(55,575)	-
Accrued expenses	117,245	127	-	117,372
Asset retirement obligations	23,982	6,197	-	30,179
Fair value of commodity derivative instruments	10,026	-	-	10,026
Total current liabilities	185,993	61,931	(55,575)	192,349
Long-term debt	689,911	-	-	689,911
Asset retirement obligations	187,790	17,141	-	204,931
Deferred tax liabilities	59,571	8,123	-	67,694
Fair value of commodity derivative instruments	3,637	-	-	3,637
Other	1,132	-	-	1,132
Total liabilities	1,128,034	87,195	(55,575)	1,159,654
Stockholders’ equity:				
Preferred stock	-	-	-	-
Common stock	40	-	-	40
Additional paid-in capital	510,469	85,479	(85,479)	510,469
Treasury stock, at cost	(20,477)	-	-	(20,477)
Retained earnings	55,941	25,712	(25,712)	55,941
Total stockholders’ equity	545,973	111,191	(111,191)	545,973

Total liabilities and stockholders' equity	$ 1,674,007	$ 198,386	$ (166,766)	$ 1,705,627

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Supplemental Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2013

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 159,902	$ 23,212	$ -	$ 183,114
Other	127	751	-	878
Total revenue	160,029	23,963	-	183,992
Costs and expenses:				
Lease operating	35,995	6,296	-	42,291
Transportation	974	-	-	974
Exploration expenditures and dry hole costs	5,145	1	-	5,146
Impairments	12	-	-	12
Depreciation, depletion and amortization	48,451	5,538	-	53,989
Accretion of liability for asset retirement obligations	5,077	1,189	-	6,266
General and administrative	6,426	-	-	6,426
Taxes, other than on earnings	225	3,060	-	3,285
Gain on sale of assets	(1,745)	-	-	(1,745)
Other	26,407	127	-	26,534
Total costs and expenses	126,967	16,211	-	143,178
Income from operations	33,062	7,752	-	40,814
Other income (expense):				
Interest income	64	-	-	64
Interest expense	(13,177)	-	-	(13,177)
Gain on derivative instruments	(30,012)	-	-	(30,012)
Income from equity investments	4,930	-	(4,930)	-
Total other income (expense)	(38,195)	-	(4,930)	(43,125)
Income (loss) before provision for income taxes	(5,133)	7,752	(4,930)	(2,311)
Provision for income taxes:				
Current	(25)	-	-	(25)
Deferred	3,874	(2,822)	-	1,052
Total provision for income taxes	3,849	(2,822)	-	1,027
Net income (loss)	$ (1,284)	$ 4,930	$ (4,930)	$ (1,284)

Supplemental Condensed Consolidating Statement of Operations

Three Months Ended September 30, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 65,339	$ 21,306	$ -	$ 86,645
Other	3,750	23	(3,750)	23
Total revenue	69,089	21,329	(3,750)	86,668
Costs and expenses:				
Lease operating	19,160	5,835	-	24,995
Transportation	160	-	-	160
Exploration expenditures and dry hole costs	977	(11)	-	966
Impairments	498	-	-	498
Depreciation, depletion and amortization	23,376	3,730	-	27,106
Accretion of liability for asset retirement obligations	2,185	1,287	-	3,472
General and administrative	5,864	3,881	(3,750)	5,995
Taxes, other than on earnings	510	2,679	-	3,189
Other	997	1	-	998
Total costs and expenses	53,727	17,402	(3,750)	67,379
Income from operations	15,362	3,927	-	19,289
Other income (expense):				
Interest income	40	-	-	40
Interest expense	(5,114)	-	-	(5,114)
Loss on derivative instruments	(22,108)	-	-	(22,108)
Income from equity investments	2,643	-	(2,643)	-
Total other income (expense)	(24,539)	-	(2,643)	(27,182)
Income (loss) before provision for income taxes	(9,177)	3,927	(2,643)	(7,893)
Provision for income taxes:				
Current	126	-	-	126
Deferred	6,804	(1,284)	-	5,520
Total provision for income taxes	6,930	(1,284)	-	5,646
Net income (loss)	$ (2,247)	$ 2,643	$ (2,643)	$ (2,247)

Supplemental Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2013

	Parent Company Only (In thousands)	Guarantor Subsidiaries	Eliminations	Consolidated
Revenue:				
Oil and natural gas	$ 483,488	$ 63,611	$ -	$ 547,099
Other	536	2,793	-	3,329
Total revenue	484,024	66,404	-	550,428
Costs and expenses:				
Lease operating	107,200	19,463	-	126,663
Transportation	2,298	19	-	2,317
Exploration expenditures and dry hole costs	9,936	3,673	-	13,609
Impairments	2,183	-	-	2,183
Depreciation, depletion and amortization	137,810	16,037	-	153,847
Accretion of liability for asset retirement obligations	15,027	3,437	-	18,464
General and administrative	20,927	-	-	20,927
Taxes, other than on earnings	848	8,036	-	8,884
Gain on sale of assets	(28,139)	(462)	-	(28,601)
Other	32,208	869	-	33,077
Total costs and expenses	300,298	51,072	-	351,370
Income from operations	183,726	15,332	-	199,058
Other income (expense):				
Interest income	91	-	-	91
Interest expense	(39,370)	-	-	(39,370)
Gain on derivative instruments	(7,033)	-	-	(7,033)
Income from equity investments	9,751	-	(9,751)	-
Total other income (expense)	(36,561)	-	(9,751)	(46,312)
Income before provision for income taxes	147,165	15,332	(9,751)	152,746
Provision for income taxes:				
Current	(175)	-	-	(175)
Deferred	(49,658)	(5,581)	-	(55,239)
Total provision for income taxes	(49,833)	(5,581)	-	(55,414)
Net income	$ 97,332	$ 9,751	$ (9,751)	$ 97,332

Supplemental Condensed Consolidating Statement of Operations

Nine Months Ended September 30, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Revenue:				
Oil and natural gas	$ 204,921	$ 79,745	$ -	$ 284,666
Other	11,254	64	(11,250)	68
Total revenue	216,175	79,809	(11,250)	284,734
Costs and expenses:				
Lease operating	47,060	15,007	-	62,067
Transportation	406	4	-	410
Exploration expenditures and dry hole costs	17,854	8	-	17,862
Impairments	6,206	-	-	6,206
Depreciation, depletion and amortization	64,088	14,844	-	78,932
Accretion of liability for asset retirement obligations	6,359	3,672	-	10,031
General and administrative	16,630	11,613	(11,250)	16,993
Taxes, other than on earnings	1,004	8,830	-	9,834
Other	4,616	-	-	4,616
Total costs and expenses	164,223	53,978	(11,250)	206,951
Income from operations	51,952	25,831	-	77,783
Other income (expense):				
Interest income	128	-	-	128
Interest expense	(15,081)	-	-	(15,081)
Loss on derivative instruments	(11,865)	-	-	(11,865)
Income from equity investments	16,377	-	(16,377)	-
Total other income (expense)	(10,441)	-	(16,377)	(26,818)
Income before provision for income taxes	41,511	25,831	(16,377)	50,965
Provision for income taxes:				
Current	(174)	-	-	(174)
Deferred	(6,680)	(9,454)	-	(16,134)
Total provision for income taxes	(6,854)	(9,454)	-	(16,308)
Net income	$ 34,657	$ 16,377	$ (16,377)	$ 34,657

Supplemental Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2013

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 282,260	$ 26,901	$ -	$ 309,161
Cash flows provided by (used in) investing activities:				
Property acquisitions	(26,979)	-	-	(26,979)
Exploration and development expenditures	(218,219)	(33,906)	-	(252,125)
Other property and equipment additions	(1,517)	-	-	(1,517)
Proceeds from sale of assets	45,232	7,005	-	52,237
Net cash used in investing activities	(201,483)	(26,901)	-	(228,384)
Cash flows provided by (used in) financing activities:				
Repayment of indebtedness	(70,000)	-	-	(70,000)
Deferred financing costs	(670)	-	-	(670)
Purchase of shares into treasury	(9,640)	-	-	(9,640)
Exercise of stock options	951	-	-	951
Net cash used in financing activities	(79,359)	-	-	(79,359)
Net increase in cash and cash equivalents	1,418	-	-	1,418
Cash and cash equivalents at the beginning of the period	1,521	-	-	1,521
Cash and cash equivalents at the end of the period	$ 2,939	$ -	$ -	$ 2,939

Supplemental Condensed Consolidating Statement of Cash Flows

Nine Months Ended September 30, 2012

	Parent Company Only	Guarantor Subsidiaries	Eliminations	Consolidated
	(In thousands)			
Net cash provided by operating activities	$ 151,193	$ 11,427	$ -	$ 162,620
Cash flows provided by (used in) investing activities:				
Property acquisitions	(34,458)	-	-	(34,458)
Exploration and development expenditures	(124,523)	(11,427)	-	(135,950)
Deposit for Hilcorp Acquisition	(55,000)			(55,000)
Other property and equipment additions	(1,474)	-	-	(1,474)
Net cash used in investing activities	(215,455)	(11,427)	-	(226,882)
Cash flows provided by (used in) financing activities:				
Deferred financing costs	(6)	-	-	(6)
Purchase of shares into treasury	(8,798)	-	-	(8,798)
Exercise of stock options	257			257
Net cash used in financing activities	(8,547)	-	-	(8,547)
Net increase in cash and cash equivalents	(72,809)	-	-	(72,809)

Cash and cash equivalents at the beginning of the period	80,128	-	-	80,128
Cash and cash equivalents at the end of the period	$ 7,319	$ -	$ -	$ 7,319

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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") which 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 2012 Annual Report and under the heading "Risk Factors" in Item 1A of Part II of this Quarterly 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 2012 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 of oil 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

On April 2, 2013, we sold certain shallow water Gulf of Mexico shelf oil and natural gas interests located within the non-operated Bay Marchand field (the "BM Interests") to the property operator for $51.5 million in cash and the buyer's assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. Our results for the nine months ended September 30, 2013 reflect a pre-tax gain of $28.1 million from this sale. See "—Liquidity and Capital Resources—Acquisitions and Dispositions" in this Item 2 for more information regarding the use of proceeds from this sale.

On September 26, 2013, we acquired from W&T Offshore, Inc. ("W&T") an asset package consisting of certain Gulf of Mexico shelf oil and natural gas interests in the West Delta 29 field (the "WD29 Interests") for $21.8 million in cash, subject to customary adjustments to reflect an economic effective date of January 1, 2013 (the "WD29 Acquisition").

We estimate that the proved reserves as of the January 1, 2013 economic effective date totaled approximately 0.6 Mmboe, of which 90% were oil and 94% were proved developed reserves. The WD29 Acquisition was funded with a portion of the proceeds from the sale of non-operated Bay Marchand assets described above.

In September and October 2013, we negotiated agreements totaling approximately $45 million with seismic companies to acquire 3D seismic licenses over our core areas. These agreements include a $35 million commitment to acquire area-wide data licenses for seismic acquisitions that will be performed by the seismic company during 2014, 2015 and 2016 covering a minimum of 200 blocks, or approximately one million acres, within the shallow water Gulf of Mexico covering our core asset base.

On March 20, 2013, we were the high bidder on five leases at the Central Gulf of Mexico Lease Sale 227. The five high bid lease blocks cover a total of 13,892 acres on a gross and net basis and are all located in the shallow Gulf of Mexico within our core area of operations. Our share of the high bids totaled approximately $2.1 million. We have been awarded all five of the leases.

Overview and Outlook

Our fiscal year 2013 capital budget is $335 million, which is allocated to development activities and exploration projects within existing core field areas. Additionally, we plan to spend approximately $46 million in 2013 on plugging, abandonment and other decommissioning activities. We budget our capital spending on exploration and development with the goal of remaining within cash flow from operations.

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 assets in the Gulf of Mexico and the Gulf Coast region that are characterized by production-weighted reserves, seismic coverage, operated positions and the ability to consolidate interests in existing properties. We believe acquisitions of this type allow us to replace and grow reserves and production as well as provide opportunities for organic reserve growth and economies of scale. 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.

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.

We believe that our core competency in plugging, abandonment and decommissioning operations will enable 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.

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 have a material adverse effect on 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 Part I, Item 1A of our 2012 Annual Report and Item 1A of Part II of this Quarterly Report for a more detailed discussion of these risks.

Results of Operations

Three Months Ended September 30, 2013

During the three months ended September 30, 2013, we completed five (5) development drilling operations, four (4) of which were successful, and six (6) recompletion operations, all of which were successful. Additionally, we drilled one successful exploratory oil well in a recently-acquired primary term lease in our Main Pass area that reached its target depth in September 2013 and is waiting on production facilities to commence production.

Our operating results for the three months ended September 30, 2013, compared to the three months ended September 30, 2012, reflect a 96% increase in oil production and a 192% increase in natural gas production. Our product mix for the three months ended September 30, 2013 was 76% oil (including natural gas liquids) compared to 82% for the three months ended September 30, 2012. Production from the acquired Hilcorp Properties had an impact of approximately 7,200 Boe per day on the production rate in the three months ended September 30, 2013, compared to results for the three months ended September 30, 2012, which do not include production from the Hilcorp Properties.

For the three months ended September 30, 2013, our total revenue increased 112%, as compared to the three months ended September 30, 2012, due primarily to the 96% increase in oil production coupled with a 5% increase in average selling prices for our oil. Our overall production volumes increased by 113% for the three months ended September 30, 2013 when compared to the three months ended September 30, 2012. Our Gulf of Mexico shelf production, excluding the recently acquired Hilcorp Properties, increased 53% in the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, due primarily to production increases in our West Delta, Main Pass and South Pass 49 fields, partially offset by production declines in our South Timbalier area. In addition, results for the three months ended September 30, 2012 include approximately 364 Boe per day associated with the recently sold BM Interests. We expect our overall production volumes to decline in the fourth quarter of 2013, primarily due to reduced production rates in our West Delta field.

In addition to the items addressed above, our net loss for the three months ended September 30, 2013 includes a gain on sale of assets of $1.7 million, a loss on abandonment activities of $22.6 million, interest expense of $13.2 million and a net loss on derivative instruments of $30.0 million as compared to interest expense of $5.1 million and a net loss on derivative instruments of $22.1 million for the three months ended September 30, 2012.

Our estimated effective income tax rate for the three months ended September 30, 2013 was 36.4%. Our estimated effective income tax rate for the three months ended September 30, 2012 was 36.6%. The decrease in our effective income tax rate is primarily related to estimated state income taxes.

Nine Months Ended September 30, 2013

During the nine months ended September 30, 2013, we completed sixteen (16) development drilling operations, thirteen (13) of which were successful, and fifteen (15) recompletion operations, thirteen (13) of which were successful. In addition, we were 100% successful in five (5) well operations that re-established production at existing wells, primarily within our Main Pass area. Additionally, we drilled one successful exploratory oil well in a recently-acquired primary term lease in our Main Pass area that reached its target depth in September 2013 and is waiting on production facilities to commence production. We also drilled one exploratory well during the nine months ended September 30, 2013, that was not successful.

Our operating results for the nine months ended September 30, 2013, compared to the nine months ended September 30, 2012, reflect an 88% increase in oil production and a 137% increase in natural gas production. Our product mix for the nine months ended September 30, 2013 was 76% oil (including natural gas liquids) compared to 80% for the nine months ended September 30, 2012. Production from the Hilcorp Properties increased our production rate by approximately 7,268 Boe per day in the nine months ended September 30, 2013, compared to results for the nine months ended September 30, 2012, which do not include production from the Hilcorp Properties. We expect our full-year 2013 oil production to increase as compared to our full-year 2012 oil production.

For the nine months ended September 30, 2013, our total revenue increased 93%, as compared to the nine months ended September 30, 2012, due primarily to the 88% increase in oil production, partially offset by slightly lower average selling prices for our oil. Our overall production volumes increased by 98% for the nine months ended September 30, 2013 when compared to the nine months ended September 30, 2012. Our Gulf of Mexico shelf production, excluding the Hilcorp Properties, increased 37% in the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, due primarily to production increases in our West Delta and South Pass 49 fields, partially offset by production declines in our South Timbalier area.

In addition to the items addressed above, our net income for the nine months ended September 30, 2013 includes a gain on sale of assets of $28.6 million, a loss on abandonment activities of $28.0 million, interest expense of $39.4 million and a net loss on derivative instruments of $7.0 million. Our net income for the nine months ended September 30, 2012 reflects significant exploration expenditures, primarily due to area-wide 2-D and 3-D seismic purchases totaling $10.7 million, impairments of $6.2 million, a loss on abandonment activities of $3.4 million, interest expense of $15.1 million and a net loss on derivative instruments of $11.9 million.

Our estimated effective income tax rate for the nine months ended September 30, 2013 was 36.4%. Our effective income tax rate for the nine months ended September 30, 2012 was 36.6%. The decrease in our estimated effective income tax rate is primarily related to estimated state income taxes. Our state income taxes primarily relate to income apportioned to Louisiana. Our estimated Louisiana income apportionment factor can change as our production mix changes and commodity prices fluctuate. Further, our estimated Louisiana income apportionment factor can impact our estimated utilization of our net operating losses. We expect that changes in these estimates will continue to result in changes in our effective income tax rate.

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,	
	2013	2012	2013	2012
Net production (per day):				
Oil (Bbls)	17,481	8,901	17,554	9,350
Natural gas (Mcf)	33,696	11,558	34,130	14,378
Total (Boe)	23,097	10,827	23,242	11,746
Average sales prices:				
Oil (per Bbl)	$ 106.85	$ 101.91	$ 106.81	$ 107.19
Natural gas (per Mcf)	3.63	3.00	3.78	2.55
Total (per Boe)	86.17	86.98	86.22	88.44
Oil and natural gas revenues (in thousands):				
Oil	$ 171,847	$ 83,453	$ 511,850	$ 274,629
Natural gas	11,267	3,192	35,249	10,037
Total	183,114	86,645	547,099	284,666
Impact of derivative instruments settled during the period (1):				
Oil (per Bbl)	$ (2.18)	$ (0.11)	$ (1.53)	$ (1.49)
Natural gas (per Mcf)	(0.01)	(0.01)	(0.05)	-
Average costs (per Boe):				
LOE	$ 19.90	$ 25.09	$ 19.96	$ 19.28
Depreciation, depletion and amortization (“DD&A”)	25.41	27.21	24.25	24.52
Accretion of liability for asset retirement obligations	2.95	3.49	2.91	3.12
Taxes, other than on earnings	1.55	3.20	1.40	3.06
General and administrative (“G&A”) expenses	3.02	6.02	3.30	5.28
Increase (decrease) in oil and natural gas revenues due to:				
Changes in prices of oil	$ 4,046		$ (973)	
Changes in production volumes of oil	84,348		238,194	
Total increase in oil sales	88,394	-	237,221	-
Changes in prices of natural gas	$ 671		$ 4,853	
Changes in production volumes of natural gas	7,404		20,359	
Total increase in natural gas sales	8,075		25,212	

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

Three Months Ended September 30, 2013 Compared to Three Months Ended September 30, 2012

Revenue and Net Loss

	Three Months Ended September 30,			
	2013	2012		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 183,114	$ 86,645	$ 96,469	111%
Net loss	(1,284)	(2,247)	963	-43%

Our oil and natural gas revenues increased primarily as a result of the 96% increase in oil production and the 192% increase in natural gas production in the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, coupled with a 5% increase in average selling prices for our oil. Oil represented 76% of total production for the three months ended September 30, 2013 as compared to 82% of total production for the three months ended September 30, 2012.

Operating Expenses

Our operating expenses primarily consist of the following:

	Three Months Ended September 30,			
	2013	2012		
	(in thousands)		$ Change	% Change
LOE	$ 42,291	$ 24,995	$ 17,296	69%
Exploration expenditures and dry hole costs	5,146	966	4,180	433%
Impairments	12	498	(486)	-98%
DD&A, including accretion expense	60,255	30,578	29,677	97%
G&A expenses	6,426	5,995	431	7%
Taxes, other than on earnings	3,285	3,189	96	3%
Other	26,534	998	25,536	NM

NM = Not meaningful

LOE increased for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, primarily due to the acquisition of the Hilcorp Properties. LOE per Boe declined for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, because the 2012 period included approximately $3.0 million of expenses related to Hurricane Isaac. There were no significant hurricane-related expenses in the 2013 period. LOE for the three months ended September 30, 2013 also included approximately $2.0 million of non-routine workover expenses.

Exploration expenditures and dry hole costs increased for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, primarily as a result of an increase in seismic and exploration expenditures. During the three months ended September 30, 2013, we recorded approximately $3.0 million of exploratory expenses. During the three months ended September 30, 2012, we recorded approximately $0.8 million of exploratory expenses. In addition, exploration expenditures include $2.1 million and $0.2 million in seismic expense during the three months ended September 30, 2013 and 2012, respectively. During the fourth quarter of 2013, we expect to incur approximately $8.0 million of exploration expense related to the recently negotiated seismic agreements.

DD&A increased for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, primarily due to the acquisition of the Hilcorp Properties. DD&A per Boe declined for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, because the per Boe rate for the Hilcorp Properties is lower than our historical DD&A rate and because of reserve additions impacting the 2013 rate.

G&A expenses increased for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, primarily as a result of higher professional fees related to the expansion of our asset base following the acquisition of the Hilcorp Properties. G&A per Boe for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, declined significantly because of the increase in production primarily from the Hilcorp Properties.

Other operating expenses increased for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012, primarily as a result of an increase in loss on abandonment activities and amortization of the premium paid for our weather derivative. During the three months ended September 30, 2013, we recorded loss on abandonment activities totaling $22.6 million and amortization expense related to our weather derivative of $4.0

million. During the three months ended September 30, 2012, we recorded no loss on abandonment activities and amortization expense related to our weather derivative of $1.0 million.

For the three months ended September 30, 2013, our loss on abandonment activities primarily reflects an increase of $21.8 million in our ARO liability related to our only remaining four non-producing wellbores in our non-operated deepwater properties. These increased abandonment costs are primarily attributable to changes in regulatory interpretations and enforcement by the Bureau of Safety and Environmental Enforcement (“BSEE”) in the deepwater that increased the required scope of work.

We revise our estimates of ARO as information about material changes to the liability becomes known. During the three months ended September 30, 2013, we recorded revisions to our ARO liability related to our shallower-water assets of $31.0 million. This does not affect current results of operations, but increases the carrying amount of our assets and will result in higher DD&A including accretion expense in future periods.

Other Income and Expense

Interest expense increased for the three months ended September 30, 2013, as compared to the three months ended September 30, 2012. For the three months ended September 30, 2013, our interest expense includes interest on our 2012 Senior Notes and borrowings on our Senior Credit Facility as well as interest on our 2011 Senior Notes. For the three months ended September 30, 2012, our interest expense consists primarily of interest on our 2011 Senior Notes.

Other income (expense) in the three months ended September 30, 2013 includes a net loss on derivative instruments of $30.0 million consisting of an unrealized loss of $26.5 million due to the change in fair value of derivative instruments to be settled in the future and a net realized loss of $3.5 million on derivative instruments settled during the quarter primarily from the impact of higher oil prices during 2013. Other income (expense) in the three months ended September 30, 2012 includes a net loss on derivative instruments of $22.1 million consisting primarily of an unrealized loss of $22.0 million due to the change in fair value of derivative instruments.

Nine Months Ended September 30, 2013 Compared to Nine Months Ended September 30, 2012

Revenue and Net Income

	Nine Months Ended September 30,			
	2013	2012		
	(in thousands)		$ Change	% Change
Oil and natural gas revenues	$ 547,099	$ 284,666	$ 262,433	92%
Net income	97,332	34,657	62,675	181%

Our oil and natural gas revenues increased primarily as a result of the 88% increase in oil production and the 137% increase in natural gas production in the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. Oil represented 76% of total production for the nine months ended September 30, 2013 as compared to 80% of total production for the nine months ended September 30, 2012.

Our net income for the nine months ended September 30, 2013 includes a gain on sale of assets totaling $28.1 million, primarily from the sale of the BM Interests.

Operating Expenses

Our operating expenses primarily consist of the following:

	Nine Months Ended September 30,			
	2013	2012		
	(in thousands)		$ Change	% Change
LOE	$ 126,663	$ 62,067	$ 64,596	104%
Exploration expenditures and dry hole costs	13,609	17,862	(4,253)	-24%
Impairments	2,183	6,206	(4,023)	-65%

DD&A, including accretion expense	172,311	88,963	83,348	94%
G&A expenses	20,927	16,993	3,934	23%
Taxes, other than on earnings	8,884	9,834	(950)	-10%
Other	33,077	4,616	28,461	617%

LOE increased for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, primarily due to the acquisition of the Hilcorp Properties. LOE per Boe increased only slightly for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012 due to the production from the Hilcorp Properties. LOE for the nine months ended September 30, 2013 also included approximately $8.0 million of non-routine workover expenses.

Exploration expenditures and dry hole costs decreased for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, primarily as a result of a decrease in seismic expense, which was $3.3 million and $10.7 million in the nine months ended September 30, 2013 and 2012, respectively. Seismic expense in the nine months ended September 30, 2012 included area-wide 2-D and 3-D seismic purchases totaling $10.7 million. We expect an increase in seismic expense in 2014 due to the recently negotiated seismic agreements. In addition, during the nine months ended September 30, 2013, we recorded approximately $3.8 million of dry hole costs, primarily associated with an exploratory drilling operation during the quarter ended June 30, 2013. During the nine months ended September 30, 2012, we recorded approximately $4.1 million of dry hole costs, primarily associated with two exploratory wells which reached their target depths in January 2012 and were determined to be unsuccessful, as well as an unsuccessful exploratory portion of a well that was successfully completed in a development zone drilled in June 2012.

Impairments for the nine months ended September 30, 2013 were primarily related to reservoir performance at a gas well in one of our smaller producing fields. 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 September 30, 2013. Impairments for the nine months ended September 30, 2012 were primarily related to the decline in our estimate of future natural gas prices, which affected two of our natural gas producing fields and reservoir performance at one of those fields.

DD&A increased for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, primarily due to the acquisition of the Hilcorp Properties. DD&A per Boe declined for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, because the per Boe rate for the Hilcorp properties is lower than our historical DD&A rate and because of reserve additions impacting the 2013 rate.

G&A expenses increased for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, primarily as a result of higher professional fees related to the expansion of our asset base following the acquisition of the Hilcorp Properties and an increase in non-cash share-based compensation. G&A per Boe for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012, declined significantly because of the increase in production primarily from the Hilcorp Properties.

Taxes, other than on earnings, were lower in the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. The decrease is primarily related to severance taxes and a decrease in production coming from state leases (which is subject to a severance tax regime).

Other operating expenses increased for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2013, primarily as a result of an increase in loss on abandonment activities and amortization of the premium paid for our weather derivative. During the nine months ended September 30, 2013, we recorded loss on abandonment activities totaling $28.0 million and amortization expense related to our weather derivative of $5.3 million. During the nine months ended September 30, 2012, we recorded loss on abandonment activities totaling $3.4 million and amortization expense related to our weather derivative of $1.4 million. For the nine months ended September 30, 2013, our loss on abandonment activities primarily reflects an increase of $21.8 million in our ARO liability related to our non-operated deepwater properties as previously described.

Other Income and Expense

Interest expense increased for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. For the nine months ended September 30, 2013, our interest expense includes interest on our 2012 Senior Notes and borrowings on our Senior Credit Facility as well as interest on our 2011 Senior Notes. For the nine months ended September 30, 2012, our interest expense consists primarily of interest on our 2011 Senior Notes.

Other income (expense) in the nine months ended September 30, 2013 includes a net loss on derivative instruments of $7.0 million consisting of an unrealized gain of $0.8 million due to the change in fair value of derivative instruments to be settled in the future and a realized loss of $7.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices. Other income (expense) in the nine months ended September 30, 2012 includes a net loss on derivative instruments of $11.9 million consisting of an unrealized loss of $8.1 million due to the change in fair value of derivative instruments which were to be settled in the future and a net realized loss of $3.8 million on derivative instruments settled during the period primarily from the impact of higher oil prices during 2012.

LIQUIDITY AND CAPITAL RESOURCES

Sources and Uses of Capital

As of October 25, 2013, we had $300 million available under our Senior Credit Facility, which has a borrowing base of $425 million. During the three months ended September 30, 2013, we reduced our borrowings under this facility to $125 million, a reduction of $40 million since June 30, 2013. Of the net proceeds of $51.7 million from the sale of our BM Interests approximately $16.5 million was used to fund the WD29 Acquisition and approximately $35 million was used in this reduction of borrowings.

Our fiscal year 2013 capital budget is $335 million, which is allocated to development activities and exploration projects within existing core field areas. Additionally, we plan to spend approximately $46 million in 2013 on plugging, abandonment and other decommissioning activities. We are in the process of preparing our 2014 capital budget.

Cash Flow and Working Capital. Net cash provided by operating activities increased to $309.2 million for the nine months ended September 30, 2013 compared to $162.6 million for the nine months ended September 30, 2012. Based on our outlook of commodity prices, our significant hedging program and our estimated production, we expect to fund our 2013 capital expenditures with cash flow from operations and borrowings under our Senior Credit Facility, as needed.

Our revenue, profitability, cash flows and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, each of which depends on numerous factors beyond our control such as economic conditions, regulatory developments and competition from other energy sources. Oil and natural gas prices historically have been volatile and may be subject to significant fluctuations in the future. Our derivative instruments serve to mitigate a portion of this price volatility on our cash flows. For the remainder of 2013, we have a total of 8,045 Bbls of oil per day hedged, the majority of which is hedged using Brent fixed price swaps at a price averaging $104.45 per Bbl. We have a total of 7,332 Mmbtu of natural gas per day hedged for the remainder of 2013, all of which is hedged using fixed price swaps at a price averaging $3.68 Mmbtu per day. For full year 2014, we have a total of 10,996 Bbls of oil per day hedged, all of which is hedged using Louisiana Light Sweet ("LLS") and Brent fixed price swaps at a price averaging $99.54 per Bbl. We have a total of 5,000 Mmbtu of natural gas per day hedged for 2014, all of which is hedged using fixed price swaps at a price averaging $4.01 Mmbtu per day. In addition, we have begun hedging forecasted 2015 production with 1,500 Bbls of oil per day currently hedged using Brent fixed price swaps at a price of $97.70 per Bbl and 4,300 Mmbtu of natural gas per day currently hedged using fixed price swaps at a price averaging $4.31 Mmbtu per day.

We have incurred, and will continue to incur, capital expenditures to achieve production targets. While we expect to fund future capital expenditures with cash flow from operations, we depend on the availability of borrowings under our Senior Credit Facility as a source of liquidity including for short-term working capital requirements. Based on anticipated oil and natural gas prices and availability under our Senior Credit Facility, we expect to be able to fund our planned capital expenditures budget, debt service requirements and working capital needs for 2013. In addition to borrowings under our Senior Credit Facility, in order to meet capital requirements, which could include the funding of future acquisitions, we also have the ability to issue debt and equity securities under our universal shelf registration statement that became effective under the Securities Act in July 2011. However, a substantial or extended decline in oil or natural gas prices could cause us to curtail our planned capital expenditures and could have a material adverse effect on our financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced. Any such substantial or extended decline could also have an adverse impact on our ability to issue additional debt or equity securities and our ability to comply with the financial covenants under our Senior Credit Facility, which in turn would limit further borrowings under our Senior Credit Facility.

At September 30, 2013, we had a working capital deficit of $125.2 million, compared to $106.3 million at December 31, 2012. Our working capital deficit at December 31, 2012 was primarily due to the use of cash to fund a portion of the Hilcorp Acquisition and increased accounts payable and accrued expenses related to exploration and development costs. The increase in our working capital deficit as of September 30, 2013 is primarily due to the continued use of cash to repay borrowings under our Senior Credit Facility, which is classified as long-term debt, and the increase in the current portion of our asset retirement obligations. We have experienced, and expect to experience in the future, significant 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, or increased investment in oil and natural gas properties. Additionally, we expect to use any available free cash flow (cash flow after capital expenditures) to reduce our debt, all of which is long-term. Therefore, although we may continue to experience working capital deficits, we expect to have significant availability under our Senior Credit Facility, providing substantial liquidity.

Capital Expenditures. During the nine months ended September 30, 2013, we incurred costs of approximately $258.3 million on development and exploration activities. In addition, we spent approximately $36.8 million on plugging, abandonment and other decommissioning activities during the nine months ended September 30, 2013. During the three months ended September 30, 2013, we recorded a revision to our ARO liability of $21.8 million related to our only remaining four non-producing wellbores in our non-operated deepwater properties. These increased abandonment costs are primarily attributable to changes in regulatory interpretations and enforcement by BSEE in the deepwater that increased the required scope of work. During the three months ended September 30, 2013, we also recorded revisions to our ARO liability related to our shallower-water assets of $31.0 million. Additionally, these factors may impact our future plans to allocate capital to abandonment and decommissioning activities, and we may reduce or curtail these activities resulting in changes to our previous estimates of timing of future cash flows.

The Bureau of Ocean Energy Management (“BOEM”), the BSEE 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 2012 Annual Report.

Acquisitions and Dispositions. On April 2, 2013, we sold our BM Interests to the property operator for $51.5 million in cash and the buyer's assumption of liabilities recorded on our balance sheet of $11.3 million resulting in total consideration of $62.8 million, subject to customary adjustments to reflect the January 1, 2013 economic effective date. We recognized a pre-tax gain of $28.1 million. The cash proceeds from this sale of assets were deposited with a qualified intermediary in contemplation of a potential tax-deferred exchange of properties and classified as restricted cash at June 30, 2013. On September 26, 2013, $16.5 million of these proceeds were used to fund the WD29 Acquisition, which was a qualifying purchase for tax-deferred purposes. On September 29, 2013, the underlying escrow agreement expired, and the remaining amount of the deposit became unrestricted.

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, resulting in a trend of increasing oil production. From time to time, we may decide to divest of certain oil and gas properties that do not meet our capital expenditure risk, rate of return, operational control or other criteria. In addition to the sale of the non-operated BM Interests, we are currently trying to determine whether there would be any interest for other small packages of our assets. However, there can be no assurance that any such small asset packages will be sold or, if so, on what terms.

Share 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 and increased the program to $40.0 million in May 2012. In July 2013, the board of directors increased the program to $80.0 million. Under the program, we have repurchased 1,799,000 shares at an aggregate cash purchase price of approximately $29.7 million, including 333,700 shares purchased for approximately $9.6 million during 2013. 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. 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, including restrictions under our Senior Credit Facility. In July 2013, our Senior Credit Facility was amended to increase the limit applicable to certain restricted payments, which includes share repurchases, permitted by the agreement.

Restricted Cash (Noncurrent). 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. 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 September 30, 2013, we had $6.0 million remaining in restricted escrow funds in the trust 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 in the noncurrent assets section of our condensed consolidated balance sheets.

8.25% Senior Notes. The 8.25% senior notes consist of $510.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the "8.25% Senior Notes") issued under an Indenture dated February 14, 2011 (the "2011 Indenture"). The 8.25% Senior 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 15th and August 15th of each year. The 8.25% Senior 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% Senior Notes will mature on February 15, 2018.

We issued the 8.25% Senior Notes in two different private placements as follows. On February 14, 2011, we issued $210.0 million in aggregate principal amount of our 8.25% senior notes due 2018 (the "2011 Senior Notes") under an Indenture dated as of February 14, 2011 (the "2011 Indenture"). We used the net proceeds from the offering of the 2011 Senior Notes of $202.0 million, after deducting the initial purchasers' discount and offering expenses payable by us, to acquire 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 from Anglo-Suisse Offshore Partners, LLC ("ASOP") for a purchase price of $200.7 million, before adjustments to reflect an economic effective date of January 1, 2011 (the "ASOP Acquisition"). For additional information regarding the 2011 Senior Notes, see Note 7, "Indebtedness," of our 2012 Annual Report.

On October 25, 2012, we issued $300.0 million in aggregate principal amount of our 2012 Senior Notes under an Indenture dated as of October 25, 2012 (the "2012 Indenture"). We used the net proceeds from the offering of the 2012 Senior Notes of $289.5 million, after deducting the initial purchasers' discount, to fund a portion of the Hilcorp Acquisition. The 2012 Senior Notes 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. The 2012 Senior Notes had terms that were substantially identical to the terms of our 2011 Senior Notes. Pursuant to a registration rights agreement executed as part of the sale of the 2012 Senior Notes (the “Registration Rights Agreement”), we have issued publicly registered additional notes under our 2011 Indenture in exchange for the 2012 Senior Notes. As a result of this exchange offer, 100% in aggregate principal amount of the 2012 Senior Notes was exchanged for the notes under the 2011 Indenture, effective as of June 10, 2013. All of the 8.25% Senior Notes are now issued under the 2011 Indenture, regardless of which private placement they were issued under. For more information regarding the 2012 Senior Notes, see Note 7, “Indebtedness,” of our 2012 Annual Report.

Senior Credit Facility. On February 14, 2011, we entered into our Senior Credit Facility with BMO Capital Markets, as lead arranger, and Bank of Montreal, as administrative agent and a lender, and the other lender parties thereto. The terms of our Senior Credit Facility established a revolving credit facility with a four-year term that could be used for revolving credit loans and letters of credit up to an aggregate principal amount of $250.0 million. On October 31, 2012, in connection with the Hilcorp Acquisition, through an amendment and restatement of our Senior Credit Facility, the aggregate commitment under this facility was increased to a maximum of $750.0 million and the maturity date was extended to October 31, 2016. The maximum amount of letters of credit that may be outstanding at any one time is $20.0 million. The amount available under the revolving credit facility is limited by the borrowing base. The Senior Credit Facility is secured by substantially all of our assets, including (a) mortgages on at least 80% of the total value of our oil and gas properties evaluated in the most recently completed reserve report, after giving effect to exploration and production activities, acquisitions and dispositions, and (b) the stock of certain wholly-owned subsidiaries. The borrowing base under our Senior 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. On October 31, 2012, the borrowing base under the expanded credit facility was increased from $200.0 million to $425.0 million. We are currently in the process our semi-annual redetermination and we expect our borrowing base will remain at $425.0 million at the conclusion of the redetermination. In addition, in July 2013, our Senior Credit Facility was amended to increase the limit applicable to certain restricted payments permitted by the agreement. Borrowings under our Senior Credit Facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. Commitment fees ranging from 0.375% to 0.50% are payable on the unused portion of the borrowing base. We had $125.0 million outstanding under our Senior Credit Facility as of September 30, 2013. As of October 25, 2013, we had $125.0 million outstanding and $300.0 million in availability under our Senior Credit Facility. For additional information regarding our Senior Credit Facility, see Note 7, “Indebtedness,” of our consolidated financial statements in Part II, Item 8 of our 2012 Annual Report.

Analysis of Cash flows – Nine months ended September 30, 2013

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

	Nine Months Ended September 30,	
	2013	2012
Cash flows from operating activities	$ 309,161	$ 162,620
Cash flows used in investing activities	(228,384)	(226,882)
Cash flows used in financing activities	(79,359)	(8,547)

The increase in our 2013 cash flows from operating activities reflects increases in revenues due primarily to the increase in our oil production during the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012.

Net cash used in investing activities remained consistent for the nine months ended September 30, 2013, as compared to the nine months ended September 30, 2012. Net cash used during the nine months ended September 30, 2013, related to exploration and development expenditures increased $116.2 million compared to the nine months ended September 30, 2012. In addition, net cash used in investing activities during the nine months ended September 30, 2013 is net of the $51.7 million in proceeds from the sale of the BM Interests partially offset by property acquisitions, while the nine months ended September 30, 2012 includes the deposit for the Hilcorp Acquisition and the acquisition of the ST41 Interests.

Net cash used in financing activities during the nine months ended September 30, 2013 primarily reflects repayments of amounts borrowed under our Senior Credit Facility as well as settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program. Net cash used in financing activities during the nine months ended September 30, 2012 primarily reflects settlements of purchases of shares of our common stock (which have been kept as treasury shares) pursuant to our repurchase program during the nine months ended September 30, 2012.

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 Senior Credit Facility and the indenture governing the 8.25% Senior 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.

New Accounting Pronouncements

Effective January 1, 2013, we adopted the amended disclosure requirements contained in ASU 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities." This guidance impacted the disclosures associated with our derivative instruments and did not impact our consolidated financial position, results of operations or cash flows. See Note 7, "Fair Value Measurements," of our condensed consolidated financial statements in Part I, Item 1 of this Quarterly Report for related disclosures.

In July 2013, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) No. 2013-11, "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists." The amendments in this update clarify the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The amendments are effective for fiscal years, and interim periods within those years, beginning December 15, 2013. We do not expect this guidance to have a material impact on our consolidated financial position, results of operations or cash flows.

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, 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," "m "anticipates," "expects," "believes," "intends," "goals," "plans," or "projects" and similar expressions.

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. Among the factors that could cause actual results to differ materially are the risks and uncertainties described under, "Risk Factors" in Item 1A of Part I of our 2012 Annual Report and Item 1A of Part II of this Quarterly 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 Senior 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 or interpretations of such regulations promulgated by the BOEM, the BSEE and the Pipeline Hazardous Materials Administration of the U.S. Department of Transportation;

•the impact of political and regulatory developments;

•risks and liabilities associated with acquired properties or businesses;

•our ability to make and integrate acquisitions;

•oil and gas prices and competition;

•cyber attacks; 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 2012 Annual Report and elsewhere in our 2012 Annual Report and Part II, Item 1A of this Quarterly 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.

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 Senior Credit Facility. Currently, we do not use interest rate derivative instruments to manage exposure to interest rate changes. At September 30, 2013 and December 31, 2012, we had \$125.0 million and \$195.0 million outstanding under our Senior Credit Facility, respectively. Borrowings under our

Senior Credit Facility bear interest ranging from a base rate plus a margin of 0.75% to 1.75% on base rate borrowings and LIBOR plus a margin of 1.75% to 2.75% on LIBOR borrowings. The maturity date of the Senior Credit Facility is October 31, 2016.

At September 30, 2013, our total indebtedness outstanding also includes $496.7 million (net of unamortized initial purchasers' discount of $13.3 million) related to our fixed-rate 8.25% Senior Notes, which bear interest at an annual fixed rate of 8.25% and mature on February 15, 2018. At September 30, 2013, the estimated fair value of our 8.25% Senior Notes was approximately $539.3 million.

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 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.

We use commodity derivative instruments to manage commodity price risks associated with future oil and natural gas production. The tables below provide information about our derivative instruments that were outstanding as of September 30,

2013. For a description of assumptions related to our calculations of fair value, please see Note 7, "Fair Value Measurements," of the condensed consolidated financial statements in Part I, Item 1 of this Quarterly Report.

Oil Contracts

	Fixed-Price Swaps Daily Average			
	Volume	Volume	Average Swap Price	Fair Value
Remaining Contract Term	(Bbls)	(Bbls)	($/Bbl)	(In thousands)
October 2013 - December 2013	7,045	648,150	$ 103.63	$ (1,840)
January 2014 - December 2014	10,996	4,013,400	99.54	(8,061)
January 2015 - December 2015	1,500	547,500	97.70	298

	Collars Daily Average			
	Volume	Volume	Strike Price	Fair Value
Remaining Contract Term	(Bbls)	(Bbls)	($/Bbl)	(In thousands)
October 2013—December 2013	1,000	92,000	$ 80.00/104.10	$ (416)

Gas Contracts

	Fixed-Price Swaps Daily Average			
	Volume	Volume	Average Swap Price	Fair Value
Remaining Contract Term	(Mmbtu)	(Mmbtu)	($/Mmbtu)	(In thousands)
October 2013 - December 2013	7,332	674,500	$ 3.68	$ 65
January 2014 - December 2014	5,000	1,825,000	4.01	265
January 2015 - December 2015	4,300	1,569,500	4.31	361

In July 2010 the United States Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. The new regulation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") imposes a new comprehensive regulatory regime on the over-the-counter derivatives market that includes, among other things, position limits and reporting, recordkeeping, margin and clearing requirements, as well as registration requirements for certain entities that are "swap dealers" or "major swap participants." Registered swap dealers and major swap participants are also subject to extensive internal and external business conduct standards and capital requirements that affect the various products offered by such entities. Under the Dodd-Frank Act, the Commodities Futures Trading Commission (the "CFTC") and the SEC are charged with implementing and overseeing this new regulatory regime. However, to date, the CFTC and SEC have yet to finalize all of the rules and regulations implementing this regime. Because the rules and regulations implementing the regulatory regime have not been completely finalized, it is uncertain what impact, if any, this new regulatory regime will have on our derivatives portfolio or our ability to continue to procure derivatives to manage our commodity price risks on terms similar to those we have successfully negotiated in the past. However, based on recent regulations promulgated by the CFTC regarding certain exceptions to the clearing requirement, we believe we will qualify for the end-user exception to the clearing requirement for swaps, and thus will not be required to clear our swaps.

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, 2013.

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, 2013 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 8, "Commitments and Contingencies" in the condensed consolidated financial statements in Part I, Item 1 of this Quarterly Report, which is incorporated by reference into Part II, Item 1 of this Quarterly Report.

Item 1A.RISK FACTORS.

In addition to the risk factor below and 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 2012 Annual Report that could materially affect our business, financial condition or future results. The risks described in this Quarterly Report on Form 10-Q and in our 2012 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 have a material adverse effect on our business, financial condition and future results.

The risk factor below is an update to the risk factors found under "Item 1A.—Risk Factors" in our 2012 Annual Report.

The cost of operating our business, including our estimates of future asset retirement obligations, may vary significantly especially because our operations are concentrated in the Gulf of Mexico.

We are responsible for plugging and abandoning wellbores and decommissioning associated platforms, pipelines and facilities on our oil and natural gas properties. Estimating future abandonment and decommissioning costs in the Gulf of Mexico is difficult because most of the removal obligations may be many years in the future, regulatory requirements are subject to change or more restrictive interpretation, and technologies are constantly evolving, which may result in increased costs. As a result, we may make significant increases or decreases to our estimated ARO in future periods. Some of our offshore operations are conducted on federal leases that are administered by the BOEM and are required to comply with the regulations and orders promulgated by the BOEM and BSEE under the Outer Continental Shelf Lands Act. We are subject to regulations over the decommissioning of wells and platforms. The regulations impose stringent requirements for decommissioning facilities that pose a hazard to safety or the environment, as well as for facilities that are not useful for lease operations and that are not capable of oil and natural gas production in "paying quantities." The regulations also impose deadlines for removing platforms or other facilities that are no longer useful for operations, and deadlines for plugging, abandoning or performing downhole zonal isolation on wells that are no longer useful for operations and that are no longer capable of production in paying quantities.

Because we operate in the Gulf of Mexico, platforms, facilities and equipment are subject to damage or destruction as a result of hurricanes. The estimated cost to plug and abandon a well or dismantle a platform can change materially if the platform from which the work was anticipated to be performed is damaged or toppled. Accordingly, our estimates of future abandonment and decommissioning costs could differ materially from what we may ultimately incur. The effects of Hurricanes Katrina and Rita during the 2005 hurricane season and Hurricanes Ike and Gustav in 2008 significantly impacted oil and gas operations on the Outer Continental Shelf ("OCS"). The effects included structural damage to fixed production facilities, semi-submersibles and jack-up drilling rigs which could create the potential for catastrophic damage to key infrastructure and the resultant pollution. The former BOEMRE has issued still active guidance through Notices to Lessees and Operators, aimed at improving platform survivability by taking into account environmental and oceanic conditions in the design of platforms and related structures.

In September 2013, after receiving further interpretations of the BSEE regulations, the estimated scope of required work increased and our estimates of future abandonment and decommissioning costs increased. It is possible that similar, if not more stringent, design and operational requirements will be issued by the BOEM or BSEE in the future and these new requirements could further increase our operating costs. The BOEM, BSEE 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.

The risk factor below is an update to the risk factor titled “We may not be insured against all of the operating risks to which our business is exposed” found under “Item 1A.—Risk Factors” in our 2012 Annual Report.

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/excess liabilities coverage with an aggregate limit of $200.0 million applicable to our working interest. Our general liability policy is subject to a $25,000 per incident deductible. We also have offshore property physical damage and operators extra expense policies that contain an aggregate of $201.4 million of named windstorm limit. Recoveries from these policies are subject to a $2.5 million deductible that applies to non-named windstorm occurrences and a $27.5 million deductible that applies to named windstorm events except for East Bay central facilities and rental compressor losses, which are subject to a 1.5% deductible of the scheduled values of the items making up a loss, but always subject to a $25,000 minimum. Further, there are sub-limits within the named windstorm annual aggregate limit for re-drill, non-blowout plugging and abandonment and excess removal of wreck. 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, to which the $50.0 million limit applies 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 regularly reevaluate the purchase of insurance, policy limits and terms. 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 will generally be 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 is structured to provide an effective method of staging response equipment and providing spill response for its member companies in the Gulf of Mexico. On January 1, 2013, CGA entered into an agreement with Clean Gulf Associates Services, LLC ("CGAS"), an affiliate of T&T Marine Salvage Inc. ("TTMS"). Through this agreement, CGAS will store, maintain, deploy and operate all CGA-owned equipment and provide response personnel. This agreement replaces the expiring Equipment Management, Contractor Services and Bareboat Charter Agreement that CGA had previously entered into with Marine Spill Response Corporation. CGAS maintains CGA's equipment in various warehouse locations (currently including 54 skimmers with various estimated daily recovery capacities, numerous containment and storage systems including thousands of feet of boom and one fire boom system, tanks and storage barges, wildlife cleaning and rehabilitation facilities, and both aerial and vessel dispersant spray systems) at staging points around the Gulf of Mexico in its ready state. In the event of a spill, CGAS 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.

Additional resources are available to the Company on an as-needed basis other than as a member of CGA, such as those of CGAS. CGAS has oil spill response equipment independent of, and in addition to, CGA's equipment. CGAS's equipment currently includes, according to CGAS's website, skimmer, containment boom, pumps and lightering equipment, vacuum units and sorbents. In the event of a spill, CGAS 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.

None

Item 3. DEFAULTS UPON SENIOR SECURITIES.

None

Item 4. MINE SAFETY DISCLOSURES.

None

Item 5. OTHER INFORMATION.

None

Item 6. EXHIBITS.

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed/ Furnished Herewith
31.1	Certification of Principal Executive Officer of EPL Oil & Gas, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification of Principal Financial Officer of EPL Oil & Gas, Inc. pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Section 1350 Certification of Principal Executive Officer of EPL Oil & Gas, Inc. pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.					X
32.2	Section 1350 Certification of Principal Financial Officer of EPL Oil & Gas, Inc. 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*	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document					X
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document					X
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document					X

*Incorporated herein by reference as indicated.

SIGNATURES

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

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 authorize

EPL Oil & Gas, Inc.

Date: October 31, 2013

By: /s/ Tiffany J. Thom

Tiffany J. Thom
Senior Vice President and
Chief Financial Officer

(Principal Financial Officer)

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