UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934

Date of report (Date of earliest event reported): September 9, 2014

DIAMONDBACK ENERGY, INC.

(Exact Name of Registrant as Specified in Charter)

Delaware	001-35700	45-4502447
(State or other jurisdiction of incorporation)	(Commission File Number)	(I.R.S. Employer Identification Number)

500 West Texas **Suite 1200** **Midland, Texas** (Address of principal executive offices)	**79701** (Zip code)

(432) 221-7400
(Registrant's telephone number, including area code)

Not Applicable
(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K is intended to simultaneously satisfy the filing obligation of the Registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act
o Soliciting material pursuant to Rule 14a-12 under the Exchange Act
o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act
o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act

Item 2.01. Completion of Acquisition or Disposition of Assets.

As previously reported by us in our Current Report on Form 8-K filed on July 21, 2014, we, through our subsidiary Diamondback E&P LLC, entered into a definitive purchase agreement dated July 18, 2014, as subsequently amended, with the following unrelated third party sellers: Rio Oil and Gas, LLC, Rio Oil and Gas (Permian) LLC, Rio Oil and Gas (OPCO), LLC, Bluestem Energy, LP, Bluestem Energy Partners, LP, Bluestem Energy Holdings, LLC, Bluestem Energy Assets, LLC, Bluestem Acquisitions, LLC, BC Operating, Inc., Crown Oil Partners V, LP and Crump Energy Partners II, LLC, pursuant to which we agreed to acquire additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas, in the Permian Basin, for an aggregate purchase price of approximately $538.0 million, subject to certain adjustments (the "Acquisition"). On September 9, 2014, we closed the Acquisition, which included approximately 17,617 gross (12,967 net) acres with a 73.6% working interest (approximately 75.1% net revenue interest) (the "West Texas Acquisition Properties"), for an adjusted purchase price of $523.6 million. During May 2014, based on information reported by the operator, net production attributable to the West Texas Acquisition Properties was approximately 2,333 BOE/d (approximately 65% oil) from 125 gross (105 net) producing vertical wells and net proved reserves as of June 1, 2014, based on our internal estimates, were approximately 5,073 MBOE. Our estimate of proved reserves is based on our analysis of production data provided by the sellers, as well as available geologic and other data, and we may revise our estimates following ownership of these properties.

We financed the Acquisition with a combination of the net proceeds from an offering of our common stock that closed on July 25, 2014 and borrowings under our revolving credit facility. Upon closing of the Acquisition, we became the operator of approximately 88% of this acreage.

The statements of revenues and direct operating expenses for the West Texas Acquisition Properties and pro forma financial information required by Items 9.01(a) and 9.01(b) of this Form 8-K (this "Form 8-K") are filed herewith as Exhibits 99.1 and 99.2, respectively.

Item 8.01. Other Events.

As previously reported, on September 18, 2013, we issued an aggregate of $450.0 million of our 6.750% Senior Notes due 2021 (the "Senior Notes"), which were initially guaranteed on a senior unsecured basis by all of our subsidiaries. On June 23, 2014, our subsidiary Viper Energy Partners LP ("Viper") completed its initial public offering of 5,750,000 common units, representing an approximate 8% limited partner interest in Viper (the "Viper IPO"). We own the general partner of Viper and the remaining approximate 92% limited partner interest in Viper. In connection with the Viper IPO, under the terms of the indenture governing the Senior Notes (the "Indenture"), we designated Viper, its general partner and Viper's subsidiary Viper Energy Partners LLC as unrestricted subsidiaries under the Indenture and upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. As a result, following the Viper IPO, the Senior Notes are guaranteed by our subsidiaries that remain restricted (the "Guarantors"). In connection with the issuance of the Senior Notes, we and the Guarantors agreed, among other things, to file a registration statement on Form S-4, as may be amended (the "Registration Statement"), with the Securities and Exchange Commission (the "SEC") to register under the Securities Act of 1933, as amended, the exchange of the Senior Notes and related guarantees for new notes (the "Exchange Notes") and guarantees with substantially identical terms, except for the transfer restrictions and registration rights that do not apply to the Exchange Notes, and different administrative terms.

In connection with the Registration Statement filed by us and the Guarantors, we are filing on this Form 8-K supplemental condensed consolidating financial information required to be included or incorporated by reference into the Registration Statement by Rule 3-10 of Regulation S-X regarding the Guarantors. In connection with the foregoing, we are filing herewith as (i) Exhibit 99.3 to this Form 8-K our audited combined consolidated financial statements contained in our Annual Report on Form 10-K for the year ended December 31, 2013 (the "10-K"), which include new Note 18 in the Notes to our audited combined consolidated financial statements, (ii) Exhibit 99.4 to this Form 8-K our unaudited consolidated financial statements contained in our Quarterly Report on Form 10-Q for the first quarter ended March 31, 2014 (the "First Quarter 10-Q"), which include new Note 14 in the Notes to our unaudited consolidated financial statements and (iii) Exhibit 99.5 to this Form 8-K our unaudited consolidated financial statements contained in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 (the "Second Quarter 10-Q" and, together with the First Quarter 10-Q, the "10-Qs"), which include new Note 15 in the Notes to our unaudited consolidated financial statements, in each case disclosing condensed consolidating financial information of the Guarantors. Except for the addition of these new Notes, no other changes or modifications have been made to our audited combined consolidated financial statements included in the 10-K or unaudited consolidated financial statements included in the 10-Qs, and no attempt has been made to update other disclosures presented in these audited consolidated financial statements or unaudited consolidated financial statements that may have been affected by subsequent events.

The information included in this Form 8-K should be read in conjunction with the 10-K, the 10-Qs and the other filings we have made, or will make, prior to the effectiveness of the Registration Statement, with the SEC.

Item 9.01. Financial Statements and Exhibits.

(a) Financial Statements of Businesses Acquired.

Statements of Revenues and Direct Operating Expenses for the West Texas Acquisition properties for the year ended December 31, 2013 (audited) and for the six months ended June 30, 2014 and 2013 (unaudited) and supplemental oil and gas reserves information (unaudited).

(b) Pro Forma Financial Information.

Unaudited Pro Forma Condensed Consolidated Financial Statements.

(d) Exhibits.

Number	Exhibit
23.1	Consent of Grant Thornton LLP relating to the West Texas Acquisition Properties.
23.2	Consent of Grant Thornton LLP relating to the audited combined consolidated financial statements of Diamondback Energy, Inc. and subsidiaries.
99.1	Statements of Revenues and Direct Operating Expenses for the West Texas Acquisition Properties for the year ended December 31, 2013 (audited) and for the six months ended June 30, 2014 and 2013 (unaudited) and supplemental oil and gas reserves information (unaudited).
99.2	Unaudited Pro Forma Condensed Consolidated Financial Statements.
99.3	Consolidated Financial Statements of Diamondback Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, as modified solely to include Note 18 providing condensed consolidating guarantor financial information.
99.4	Unaudited Consolidated Financial Statements of Diamondback Energy, Inc. and subsidiaries as of March 31, 2014 and 2013, and for the quarters ended March 31, 2014 and 2013, as modified solely to include Note 14 providing condensed consolidating guarantor financial information.
99.5	Unaudited Consolidated Financial Statements of Diamondback Energy, Inc. and subsidiaries as of June 30, 2014 and 2013, and for the quarters ended June 30, 2014 and 2013, as modified solely to include Note 15 providing condensed consolidating guarantor financial information.

SIGNATURE

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

DIAMONDBACK ENERGY, INC.

Date: September 12, 2014

By: /s/ Teresa L. Dick
Teresa L. Dick
Senior Vice President and Chief Financial Officer

Exhibit Index

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Exhibit 23.1

CONSENT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

We have issued our report dated September 12, 2014, with respect to the statement of revenues and direct operating expenses of the West Texas Acquisition Properties acquired by Diamondback Energy, Inc. for the year ended December 31, 2013, included in this Current Report of Diamondback Energy, Inc. on Form 8-K. We hereby consent to the incorporation by reference of said report in the Registration Statements of Diamondback Energy, Inc. on Form S-3 (File No. 333-192099), on Form S-8 (File No. 333-188552) and on Form S-4, as amended (File No. 333-194567).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
September 12, 2014

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 19, 2014 (except for Note 18, as to which the date is September 12, 2014), with respect to the combined consolidated financial statements of Diamondback Energy, Inc. as subsidiaries as of December 31, 2013 and 2012 and for each of the three years in the period ended December 31, 2013, included in this Current Report of Diamondback Energy, Inc. on Form 8-K. We hereby consent to the incorporation by reference of said report in the Registration Statements of Diamondback Energy, Inc. on Form S-3 (File No. 333-192099), on Form S-8 (File No. 333-188552) and on Form S-4, as amended (File No. 333-194567).

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
September 12, 2014

Following are the Statements of Revenues and Direct Operating Expenses of the West Texas Acquisition Properties (as described in Note 1):

REPORT OF INDEPENDENT CERTIFIED PUBLIC ACCOUNTANTS

Board of Directors and Stockholders
Diamondback Energy, Inc.

We have audited the accompanying statement of revenues and direct operating expenses of the West Texas Acquisition Properties acquired by Diamondback Energy, Inc. for the year ended December 31, 2013 and the related notes to the financial statement.

Management's responsibility for the financial statements

Management is responsible for the preparation and fair presentation of the financial statement in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of the financial statement that is free from material misstatement, whether due to fraud or error.

Auditor's responsibility

Our responsibility is to express an opinion on the financial statement based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statement is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statement. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statement in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statement.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statement referred to above presents fairly, in all material respects, the revenues and direct operating expenses of the West Texas Acquisition Properties acquired by Diamondback Energy, Inc. in accordance with accounting principles generally accepted in the United States of America.

Emphasis of matter

As described in Note 1, the accompanying financial statement is prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission and are not intended to be a complete presentation of the West Texas Acquisition Properties’ revenues and expenses. Our opinion is not modified with respect to this matter.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
September 12, 2014

WEST TEXAS ACQUISITION PROPERTIES

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

(In thousands)

	Year Ended December 31,	Six Months Ended June 30,	
	2013	2014	2013
		(Unaudited)	
Revenues	$ 41,701	$ 26,488	$ 20,261
Direct operating expenses:			
Lease operating expenses	9,926	8,376	4,520
Production taxes	2,953	1,777	1,449
Total direct operating expenses	12,879	10,153	5,969
Excess of revenues over direct operating expenses	$ 28,822	$ 16,335	$ 14,292

See accompanying notes to the Statements of Revenues and Direct Operating Expenses

West Texas Acquisition Properties

Notes to Statements of Revenues and Direct Operating Expenses

NOTE 1 - PROPERTIES AND BASIS OF PRESENTATION

On July 18, 2014, Diamondback E&P LLC, a wholly owned subsidiary of Diamondback Energy, Inc. (the “Company”), entered into a Purchase and Sale Agreement (the “Agreement”) with unrelated third party sellers (the “Sellers”) to acquire additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas, in the Permian Basin (the “West Texas Acquisition Properties”). The aggregate purchase price, subject to adjustment as provided in the Agreement, was $538.0 million.

The accompanying statements of revenues and direct operating expenses represents the acquired net working and net revenue interests of approximately 16,773 gross (13,136 net) acres located in the Permian Basin of West Texas. The accompanying statements of revenues and direct operating expenses vary from a complete income statement in accordance with accounting principles generally accepted in the United States of America in that they do not reflect certain expenses incurred in connection with the ownership and operation of the West Texas Acquisition Properties, including but not limited to depreciation, depletion and amortization, accretion of asset retirement obligations, general and administrative expenses, interest expense and federal and state income taxes. Furthermore, no balance sheet has been presented for the West Texas Acquisition Properties because the acquired properties were not accounted for as or operated as a separate subsidiary or division by the Sellers and complete historical financial statements are not available, nor has information about the West Texas Acquisition Properties’ operating, investing and financing cash flows been provided for similar reasons. Accordingly, the historical statements of revenues and direct operating expenses of the West Texas Acquisition Properties are presented in lieu of complete financial statements required under Rule 3-05 of the Securities and Exchange Commission Regulation S-X.

The accompanying statements of revenues and direct operating expenses are presented on the accrual basis of accounting and were derived from the historical accounting records of the Sellers. Such amounts may not be representative of future operations.

The accompanying statements of revenues and direct operating expenses for the six months ended June 30, 2014 and 2013 are unaudited. The unaudited interim statements of revenues and direct operating expenses have been derived from the Sellers’ historical accounting records and prepared on the same basis as the annual statement of revenues and direct operating expenses. In the opinion of management, such unaudited interim statements reflect all adjustments necessary to fairly present the West Texas Acquisition Properties’ excess of revenue over direct operating expenses for the six months ended June 30, 2014 and 2013.

NOTE 2 - SIGNIFICANT ACCOUNTING POLICIES

Use of estimates

The preparation of the accompanying statements of revenues and direct operating expenses in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of revenues and direct operating expenses during the reporting period. The estimates include oil and gas revenue accruals and reserve quantities. It is emphasized that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Actual results could materially differ from these estimates.

Revenue recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable.

NOTE 3 - SUBSEQUENT EVENTS

The Company has evaluated subsequent events through September 12, 2014, the date the statements of revenues and direct operating expenses were available to be issued, and has concluded that no events need to be reported in relation to this period.

NOTE 4 - SUPPLEMENTAL OIL AND GAS RESERVE INFORMATION (UNAUDITED)

The reserve estimates at December 31, 2013 presented in the table below were estimated by qualified petroleum engineers of the Company using historical data and other information from the records of the third party Sellers' of the West Texas Acquisition Properties.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The following table sets forth the estimated net proved developed and undeveloped oil and natural gas reserves related to the West Texas Acquisition Properties at December 31, 2013:

	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Reserves:			
As of January 1, 2013	3,654,503	530,502	7,349,207
Production	(366,205)	(136,199)	(768,563)
As of December 31, 2013	3,288,298	394,303	6,580,644
Proved Developed Reserves:			
January 1, 2013	3,654,503	530,502	7,349,207
December 31, 2013	3,288,298	394,303	6,580,644
Proved Undeveloped Reserves:			
January 1, 2013	—	—	—
December 31, 2013	—	—	—

Standardized Measure of Discounted Future Net Cash Flows

The following information has been prepared in accordance with the provisions of the FASB Codification, Topic 932– "Extractive Activities—Oil and Gas." The standardized measure of discounted future net cash flows are based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The standardized measure of discounted future net cash flows represents the present value of estimated future net cash flows from net proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs, and estimated future income tax expenses, discounted at 10% per annum to reflect timing of future cash flows. Production costs do not include depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the West Texas Acquisition Properties proved oil and natural gas reserves as of December 31, 2013:

	December 31, 2013 (In thousands)
Future cash inflows	$ 336,784
Future development costs	(24,732)
Future production costs	(111,562)
Future production taxes	(24,458)
Future income tax expenses	(2,357)
Future net cash flows	173,675
10% discount to reflect timing of cash flows	(83,437)
Standardized measure of discounted future net cash flows	$ 90,238

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows.

	December 31, 2013 Unweighted Arithmetic Average First-Day-of-the-Month Prices
Oil (per Bbl)	$ 91.85
Natural gas (per Mcf)	$ 3.69
Natural gas liquids (per Bbl)	$ 34.92

Principal changes in the standardized measure of discounted future net cash flows attributable to estimated net proved oil and natural gas reserves of the West Texas Acquisition Properties for the period presented:

	Year Ended December 31, 2013 (In thousands)
Standardized measure of discounted future net cash flows at the beginning of the period	$ 101,943
Sales of oil and natural gas, net of production costs	(28,822)
Net changes in prices and production costs	6,719
Accretion of discount	10,194
Net change in income taxes	160
Net changes in timing of production and other	44
Standardized measure of discounted future net cash flows at the end of the period	$ 90,238

UNAUDITED PRO FORMA CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

On July 18, 2014, Diamondback E&P LLC, a wholly owned subsidiary of Diamondback Energy, Inc. (the “Company”), entered into a Purchase and Sale Agreement (the “Agreement”) with unrelated third party sellers (the “Sellers”) to acquire additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas, in the Permian Basin (the “West Texas Acquisition Properties” or the “West Texas Acquisition”). The aggregate purchase price, as adjusted and subject to final closing adjustments as provided in the Agreement, was $523.3 million.

On February 27 and 28, 2014, Diamondback Energy, Inc. completed the acquisition of certain oil and natural gas properties from Henry Resources, LLC and certain of its affiliates (the “Henry Group Properties” or the “Henry Group”) and from Lime Rock Resources II-A, L.P. and an affiliate (the “Lime Rock Properties” or “Lime Rock”), respectively. The aggregate purchase price was $292.2 million.

The following unaudited pro forma condensed consolidated financial information and related notes are based on the historical financial statements of Diamondback Energy, Inc. and Subsidiaries (“Diamondback” or the “Company,” and also referred to as “we,” “us” or “our”), adjusted on a pro forma basis to give effect to its acquisition of the West Texas Acquisition Properties and the Henry Group and Lime Rock Properties as described above. For purposes of the pro forma financial information, the acquisition of the West Texas Acquisition Properties, Henry Group Properties and Lime Rock Properties was assumed to be funded from (i) cash on hand, (ii) with regards to the West Texas Acquisition Properties the Company completed an underwritten public offering of 5,750,000 shares of its common stock at a price to the public of $87.00 per share, which the Company received net proceeds of approximately $484.9 million (iii) with regards to the Henry Group Properties and Lime Rock Properties acquisition the Company completed an underwritten public offering of 3,450,000 shares of its common stock at a price to the public of $62.67, which the Company received net proceeds of approximately $208.4 million and (iv) from borrowing under the Company’s revolving credit facility.

The unaudited pro forma condensed consolidated balance sheet as of June 30, 2014 is based on Diamondback’s historical unaudited consolidated balance sheet and assumes the West Texas Acquisition and related funding transactions occurred on June 30, 2014. The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2013 is based on Diamondback’s historical audited consolidated statement of operations, the audited statement of revenues and direct operating expenses of the West Texas Acquisition Properties and the audited carve-out financial statements of Henry Group and Lime Rock Properties, and was prepared as if the acquisitions had occurred on January 1, 2013. The unaudited pro forma condensed consolidated statement of operations for the six months ended June 30, 2014 is based on Diamondback’s historical unaudited consolidated statement of operations, the unaudited statement of revenues and direct operating expenses of the West Texas Acquisition Properties and the unaudited historical results for the period of January 1, 2014 through February 27 and 28, 2014 from Henry Group and Lime Rock, respectively, and was prepared as if the acquisitions had occurred on January 1, 2013.

The unaudited pro forma condensed consolidated financial information is provided for informational purposes only. The unaudited pro forma condensed consolidated statements of operations are not necessarily indicative of operating results that would have been achieved had the acquisitions been completed as of January 1, 2013, and should not be taken as representative of our future consolidated results of operations or financial condition. The unaudited pro forma condensed consolidated balance sheet does not purport to reflect what Diamondback’s financial condition would have been had the West Texas Acquisition transaction closed on June 30, 2014 or for any future or historical period. The accompanying unaudited pro forma condensed consolidated financial statements are based on assumptions and include adjustments as explained in the notes thereto. Certain information (including substantial footnote disclosures) included in our annual historical consolidated financial statements has been excluded in these unaudited pro forma condensed consolidated financial statements.

The unaudited pro forma condensed consolidated financial statements should be read in conjunction with the following information:

- notes to the unaudited pro forma condensed consolidated financial information;
- our Annual Report on Form 10-K for the year ended December 31, 2013, filed with the SEC on February 19, 2014;
- our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014, filed with the SEC on August 7, 2014;
- our Current Reports on Form 8-K, filed with the SEC on July 21, 2014 (which describes the West Texas Acquisition) and July 25, 2014;
- our Current Reports on Form 8-K, filed with the SEC on February 18, 2014, February 26, 2014 and March 5, 2014 (which describes the Henry Group and Lime Rock acquisitions);
- Henry Group Properties audited carve-out financial statements as of and for the year ended December 31, 2013, included as exhibit 99.1 to Amendment No. 1 to our Current Report on Form 8-K/A filed with the SEC on May 14, 2014;
- Lime Rock Properties audited carve-out financial statements as of and for the year ended December 31, 2013, included as exhibit 99.2 to Amendment No. 1 to our Current Report on Form 8-K/A filed with the SEC on May 14, 2014;
- West Texas Acquisition Properties audited statement of revenues and direct operating expenses for the year ended December 31, 2013, included as exhibit 99.1 to this Current Report on Form 8-K.
- West Texas Acquisition Properties unaudited statement of revenues and direct operating expenses for the six months ended June 30, 2014 and 2013, included as exhibit 99.1 to this Current Report on Form 8-K.

Diamondback Energy, Inc. and Subsidiaries
Unaudited Pro Forma Condensed Consolidated Balance Sheet
As of June 30, 2014

	Diamondback Historical	West Texas Acquisition Pro Forma Adjustments		Pro Forma Combined
		(In thousands)		
Assets				
Current assets:				
Cash and cash equivalents	$ 36,993	$ 484,900	(a)	$ 8,633
		(523,260)	(b)	
		10,000	(c)	
Accounts receivable	65,345	42	(b)	65,387
Accounts receivable - related party	3,310	—		3,310
Inventories	3,308	—		3,308
Deferred income taxes	4,327	—		4,327
Prepaid expenses and other	1,421	—		1,421
Total current assets	114,704	(28,318)		86,386
Property and equipment				
Oil and natural gas properties, based on the full cost method of accounting	2,191,321	527,836	(b)	2,719,157
Pipeline and gas gathering assets	6,846	—		6,846
Other property and equipment	4,973	—		4,973
Accumulated depletion, depreciation, amortization and impairment	(283,152)	—		(283,152)
	1,919,988	527,836		2,447,824
Other assets	12,702	—		12,702
Total assets	$ 2,047,394	$ 499,518		$ 2,546,912
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable-trade	$ 23,475	$ —		$ 23,475
Accounts payable-related party	67	—		67
Other current liabilities	145,335	3,532	(b)	148,867
Total current liabilities	168,877	3,532		172,409
Long-term debt	496,000	10,000	(c)	506,000
Asset retirement obligations	5,437	1,086	(b)	6,523
Deferred income taxes	124,743	—		124,743
Total liabilities	795,057	14,618		809,675
Commitments and contingencies				
Stockholders' equity	1,114,901	484,900	(a)	1,599,801
Noncontrolling interest	137,436	—		137,436
Total equity	1,252,337	484,900		1,737,237
Total liabilities and equity	$ 2,047,394	$ 499,518		$ 2,546,912

See Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements

Diamondback Energy, Inc. and Subsidiaries
Unaudited Pro Forma Condensed Consolidated Statement of Operations
For the Six Months Ended June 30, 2014

	Diamondback Historical	Henry Group Properties Historical	Lime Rock Properties Historical	West Texas Acquisition Properties Historical	Pro Forma Adjustments		Pro Forma Combined
	(In thousands, except per share amounts)						
Revenues:							
Oil and gas revenues	$ 225,008	$ 6,101	$ 3,874	$ 26,488	$ —		$ 261,471
Total revenues	225,008	6,101	3,874	26,488	—		261,471
Costs and expenses:							
Lease operating expenses	18,411	856	544	8,376	—		28,187
Production and ad valorem taxes	14,396	408	259	1,777	—		16,840
Gathering and transportation	1,285	—	—	—	—		1,285
Depreciation, depletion and amortization	70,994	—	—	—	12,007	(bb)	83,001
General and administrative expenses	8,491	—	—	—	—		8,491
Asset retirement obligation accretion expense	176	—	—	—	32	(cc)	208
Total costs and expenses	113,753	1,264	803	10,153	12,039		138,012
Income from operations	111,255	4,837	3,071	16,335	(12,039)		123,459
Other income (expense)							
Interest income	—	—	—	—	—		—
Interest expense	(14,244)	—	—	—	(1,449)	(ee)	(15,693)
Other income - related party	60	—	—	—	—		60
Other expense	(1,408)	—	—	—	—		
Loss on derivative instruments, net	(15,486)	—	—	—	—		(15,486)
Total other income (expense), net	(31,078)	—	—	—	(1,449)		(31,119)
Income before income taxes	80,177	4,837	3,071	16,335	(13,488)		92,340
Provision for income taxes							
Current	—	—	—	—	—		—
Deferred	28,764	—	—	—	4,479	(hh)	33,243
Net income	51,413	4,837	3,071	16,335	(17,967)		59,097
Less: Net income attributable to noncontrolling interest	71	—	—	—	—		71
Net income attributable to Diamondback Energy, Inc.	$ 51,342	$ 4,837	$ 3,071	$ 16,335	$ (17,967)		$ 59,026
Earnings per common share							
Basic	$ 1.03						$ 1.00
Diluted	$ 1.02						$ 1.00
Weighted average common shares outstanding							
Basic	49,622				9,204		58,826
Diluted	50,047				9,204		59,251

See Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements

Diamondback Energy, Inc. and Subsidiaries
Unaudited Pro Forma Condensed Consolidated Statement of Operations
For the Year Ended December 31, 2013

	Diamondback Historical	Henry Group Properties Historical	Lime Rock Properties Historical[1]	West Texas Acquisition Properties Historical	Pro Forma Adjustments		Pro Forma Combined
	(In thousands, except per share amounts)						
Revenues:							
Oil and gas revenues	$ 208,002	$ 39,166	$ 25,490	$ 41,701	$ 1,377	(aa)	$ 315,736
Total revenues	208,002	39,166	25,490	41,701	1,377		315,736
Costs and expenses:							
Lease operating expenses[2]	21,157	5,050	3,064	9,926	164	(aa)	39,361
Production and ad valorem taxes[2]	12,899	2,411	1,480	2,953	23	(aa)	19,766
Gathering and transportation	918	—	—	—	—		918
Depreciation, depletion and amortization	66,597	12,586	8,418	—	8,197	(bb)	95,798
General and administrative expenses	11,036	1,869	224	—	—		13,129
Asset retirement obligation accretion expense	201	70	46	—	18	(cc)	335
Total costs and expenses	112,808	21,986	13,232	12,879	8,402		169,307
Income from operations	95,194	17,180	12,258	28,822	(7,025)		146,429
Other income (expense)							
Interest income	1	—	—	—	—		1
Interest expense	(8,059)	—	(1,308)	—	1,308	(dd)	(10,827)
					(2,768)	(ee)	
Other income - related party	1,077	—	—	—	—		1,077
Loss on derivative instruments, net	(1,872)	(512)	—	—	512	(ff)	(1,872)
Total other income (expense), net	(8,853)	(512)	(1,308)	—	(948)		(11,621)
Income before income taxes	86,341	16,668	10,950	28,822	(7,973)		134,808
Provision for income taxes							
Current	191	169	107	—	(276)	(gg)	191
Deferred	31,563	—	—	—	16,777	(hh)	48,340
Net income	$ 54,587	$ 16,499	$ 10,843	$ 28,822	$ (24,474)		$ 86,277
Earnings per common share							
Basic	$ 1.30						$ 1.68
Diluted	$ 1.29						$ 1.68
Weighted average common shares outstanding							
Basic	42,015				9,204		51,219
Diluted	42,255				9,204		51,459

(1) The amounts presented above include reclassification adjustments to convert the basis of accounting for oil and natural gas properties from successful efforts to full cost method. Refer to Note 3 below for further discussion.

(2) Reclassification of ad valorem taxes from lease operating expenses to the production and ad valorem taxes were made to conform to Diamondback's financial statement presentation. Refer to Note 3 below for further discussion.

See Notes to Unaudited Pro Forma Condensed Consolidated Financial Statements

1. DESCRIPTION OF THE TRANSACTIONS

On July 18, 2014, Diamondback E&P LLC, a wholly owned subsidiary of Diamondback Energy, Inc. (the "Company"), entered into a Purchase and Sale Agreement (the "Agreement") with unrelated third party sellers (the "Sellers") to acquire additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas, in the Permian Basin (the "West Texas Acquisition Properties" or the "West Texas Acquisition"). The aggregate purchase price, as adjusted and subject to final closing adjustments as provided in the Agreement, was $523.3 million.

On February 27 and 28, 2014, Diamondback Energy, Inc. completed the acquisition of certain oil and natural gas properties from Henry Resources, LLC and certain of its affiliates (the "Henry Group Properties" or the "Henry Group") and from Lime Rock Resources II-A, L.P. and an affiliate (the "Lime Rock Properties" or "Lime Rock"), respectively. The aggregate purchase price was $292.2 million.

2. BASIS OF PRESENTATION

The following unaudited pro forma condensed consolidated financial information and related notes are based on the historical consolidated financial statements of Diamondback Energy, Inc. and Subsidiaries ("Diamondback" or the "Company," and also referred to as "we," "us" or "our"), adjusted on a pro forma basis to give effect to its acquisition of the West Texas Acquisition Properties and the Henry Group and Lime Rock Properties as described above. For purposes of the pro forma financial information, the acquisition of the West Texas Acquisition Properties, Henry Group Properties and Lime Rock Properties was assumed to be funded from (i) cash on hand, (ii) with regards to the West Texas Acquisition Properties the Company completed an underwritten public offering of 5,750,000 shares of its common stock at a price to the public of $87.00 per share, which the Company received net proceeds of approximately $484.9 million (iii) with regards to the Henry Group Properties and Lime Rock Properties acquisition the Company completed an underwritten public offering of 3,450,000 shares of its common stock at a price to the public of $62.67, which the Company received net proceeds of approximately $208.4 million and (iv) from borrowing under the Company's revolving credit facility.

The unaudited pro forma condensed consolidated balance sheet as of June 30, 2014 is based on Diamondback's historical unaudited consolidated balance sheet and assumes the West Texas Acquisition and related funding transactions occurred on June 30, 2014. The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2013 is based on Diamondback's historical audited consolidated statement of operations, the audited statement of revenues and direct operating expenses of the West Texas Acquisition Properties and the audited carve-out financial statements of Henry Group and Lime Rock Properties after giving effect to the Henry Group and Lime Rock Transaction and after applying the reclassifications and adjustments described in the accompanying notes to the unaudited pro forma condensed consolidated financial statements. The unaudited pro forma condensed consolidated financial statements have adjusted the Lime Rock oil and natural gas properties accounted for under the successful efforts method to the full cost method. The unaudited pro forma condensed consolidated statement of operations for the year ended December 31, 2013 was prepared as if the acquisitions had occurred on January 1, 2013. The unaudited pro forma condensed statement of operations for the six months ended June 30, 2014 is based on Diamondback's historical unaudited consolidated statement of operations, the unaudited statement of revenues and direct operating expenses of the West Texas Acquisition Properties and the unaudited historical results for the period of January 1, 2014 through February 27 and 28, 2014 from Henry Group and Lime Rock, respectively, and was prepared as if the acquisitions had occurred on January 1, 2013.

The unaudited pro forma condensed consolidated financial information is provided for informational purposes only. The unaudited pro forma condensed consolidated statements of operations are not necessarily indicative of operating results that would have been achieved had the acquisitions been completed as of January 1, 2013, and should not be taken as representative of our future consolidated results of operations or financial condition. The unaudited pro forma condensed consolidated balance sheet does not purport to reflect what Diamondback's financial condition would have been had the West Texas Acquisition transaction closed on June 30, 2014 or for any future or historical period. The accompanying unaudited pro forma condensed consolidated financial statements are based on assumptions and include adjustments as explained in the notes thereto. Certain information (including substantial footnote disclosures) included in our annual historical consolidated financial statements has been excluded in these unaudited pro forma condensed consolidated financial statements.

3. RECLASSIFICATIONS

Reclassification of ad valorem taxes from lease operating expenses to the production and ad valorem taxes were made to conform to Diamondback's financial statement presentation. For the Henry Group Properties a reclassification of $661,000 was made from lease operating expense to production and ad valorem taxes. For the Lime Rock Properties a reclassification of $434,000 was made from lease operating expense to production and ad valorem taxes.

LIME ROCK PROPERTIES
CARVE-OUT STATEMENT OF REVENUES AND EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 2013

	Lime Rock Properties	Reclassification Adjustments		As Presented in Unaudited Condensed Statement of Operations
		(In thousands)		
Revenues:				
Oil and gas revenues	$ 25,490	$ —		$ 25,490
Total revenues	25,490	—		25,490
Costs and expenses:				
Lease operating expenses	3,498	(434)	(a)	3,064
Production and ad valorem taxes	1,046	434	(a)	1,480
Depreciation, depletion and amortization	11,730	(3,312)	(b)	8,418
General and administrative expenses	224	—		224
Asset retirement obligation accretion expense	46	—		46
Total costs and expenses	16,544	(3,312)		13,232
Income from operations	8,946	3,312		12,258
Other income (expense)				
Interest income	—	—		—
Interest expense	(1,308)	—		(1,308)
Total other income (expense), net	(1,308)	—		(1,308)
Income before income taxes	7,638	3,312		10,950
Provision for income taxes				
Current	87	20	(b)	107
Net income	$ 7,551	$ 3,292		$ 10,843

(a) These reclassifications were made to conform to Diamondback's presentation.

(b) These adjustments are necessary to convert the method of accounting for oil and natural gas properties from successful efforts to full cost. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. The conversion to full cost has resulted in a deferred tax asset.

4. PRO FORMA ADJUSTMENTS

The following pro forma adjustments have been reflected in the unaudited pro forma condensed financial statements. Such information does not purport to be indicative of the results of operations or financial position that actually would have resulted had the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions occurred on the date indicated, nor is it indicative of the results that may be expected in future periods. The pro forma adjustments are based upon information and assumptions available at the time of filing the Current Report on Form 8-K/A to which these unaudited pro forma condensed financial statements are an exhibit.

Diamondback made the following adjustments and assumptions in the preparation of the unaudited pro forma condensed consolidated balance sheet.

(a) On July 25, 2014, Diamondback closed an underwritten public offering of an aggregate 5,750,000 shares of its common stock at a price to the public of $87.00 per share. Diamondback received net proceeds of approximately $484.9 million and used the net proceeds to fund the West Texas Acquisition.

(b) The allocation of the purchase price to the assets acquired and liabilities assumed is preliminary and, therefore subject to change. The allocation of the purchase price of the West Texas Acquisition to the fair value of the assets acquired and liabilities assumed is as follows:

	West Texas Acquisition Properties (in thousands)
Consideration transferred for West Texas Acquisition:	
Cash	$ 523,260
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved oil and natural gas properties	$ 96,143
Unevaluated oil and natural gas properties	431,693
Joint interest receivables	42
Total assets acquired	527,878
Accrued production and ad valorem taxes	358
Revenues payable	3,174
Asset retirement obligations	1,086
Total liabilities assumed	4,618
Total fair value of net assets	$ 523,260

(c) Reflects borrowings under Diamondback’s revolving credit facility to fund the West Texas Acquisition.

Diamondback made the following adjustments and assumptions in the preparation of the unaudited pro forma condensed consolidated statements of operations.

(aa) These pro forma adjustments include immaterial amounts attributable to the acquisition of oil and natural gas interests from working interest owners with de minimis interests.

(bb) Reflects depletion, depreciation and amortization of oil and natural gas properties associated with the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions recorded on a combined basis under the full cost method. Costs associated with evaluated properties are amortized using a unit-of-production basis under the full cost method of accounting.

(cc) Reflects accretion of discount on asset retirement obligations associated with the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions recorded on a combined basis.

(dd) Reflects the elimination of interest expense from Lime Rock as the associated debt was not assumed in the Lime Rock Properties acquisition.

(ee) Reflects estimated interest expense associated with borrowings under Diamondback’s revolving credit agreement to fund a portion of the purchase price of the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions.

Diamondback is subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The outstanding borrowings under the credit agreement bear interest at a rate elected by Diamondback that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base.An increase or decrease of 1/8% in the interest rate would have a corresponding decrease or increase in our pro forma interest expense of approximately $123,000 and $61,000 for the year ended December 31, 2013 and for the six months ended June 30, 2014, respectively, based on the $97,000,000 aggregate pro forma assumed borrowing in conjunction with the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions.

(ff) Reflects the elimination of loss on derivatives from Henry Group as the associated derivative contracts were not assumed in the Henry Group Properties acquisition.

(gg) Reflects the elimination of current income tax provision from Henry Group and Lime Rock as the income tax provision is calculated on a combined basis as reflected in adjustment (hh).

(hh) Reflects estimated incremental income tax provision associated with the additional operating income from the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions and the pro forma adjustments using a combined federal and state statutory tax rate of 36.0%.

4. SUPPLEMENTAL PRO FORMA COMBINED OIL AND GAS RESERVE AND STANDARDIZED MEASURE INFORMATION (Unaudited)

The following table sets forth unaudited pro forma information with respect to Diamondback's estimated proved reserves, including changes therein, and proved developed and proved undeveloped reserves for the year ended December 31, 2013, giving effect to the Transaction as if it had occurred on January 1, 2013. The estimates of reserves attributable to the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions may include development plans for those properties which are different from those that the Company will ultimately implement. Reserve estimates are inherently imprecise, require extensive judgments of reservoir engineering data and are generally less precise than estimates made in connection with financial disclosures.

	Diamondback Historical			Henry Group Historical			Lime Rock Historical			West Texas Acquisition Properties Historical			Total Pro Forma		
	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:															
As of January 1, 2013	26,196,859	8,251,429	34,570,148	3,223,340	—	6,987,738	2,344,582	514,807	2,115,741	3,654,503	530,502	7,349,207	35,419,284	9,296,738	51,022,834
Extensions and discoveries	17,041,744	4,597,856	24,184,540	33,996	—	64,528	—	—	—	—	—	—	17,075,740	4,597,856	24,249,068
Revisions of previous estimates	(5,943,164)	(3,455,306)	(5,786,180)	138,164	—	1,491,399	(115,373)	(141,326)	478,102	—	—	—	(5,920,373)	(3,596,632)	(3,816,679)
Purchase of reserves in place	7,328,162	1,672,824	10,441,485	—	—	—	—	—	—	—	—	—	7,328,162	1,672,824	10,441,485
Production	(2,022,749)	(361,079)	(1,730,497)	(373,884)	—	(689,297)	(245,726)	—	(453,024)	(366,205)	(136,199)	(768,563)	(3,008,564)	(497,278)	(3,641,381)
As of December 31, 2013	42,600,852	10,705,724	61,679,496	3,021,616	—	7,854,368	1,983,483	373,481	2,140,819	3,288,298	394,303	6,580,644	50,894,249	11,473,508	78,255,327
Proved Developed Reserves:															
December 31, 2013	19,789,965	4,973,493	31,428,756	2,647,251	—	7,112,044	1,769,687	338,935	1,944,738	3,288,298	394,303	6,580,644	27,495,201	5,706,731	47,066,182
Proved Undeveloped Reserves:															
December 31, 2013	22,810,887	5,732,231	30,250,740	374,365	—	742,324	213,795	34,546	196,080	—	—	—	23,399,047	5,766,777	31,189,144

The following pro forma standardized measure of the discounted net future cash flows and changes applicable to proved reserves reflect the effect of income taxes assuming the West Texas Properties, Henry Group Properties and Lime Rock Properties acquisitions had been subject to federal income tax at a rate of 35%. The future net cash flows are based on a 10% annual discount rate. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to Diamondback. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

	Diamondback Historical	Henry Group Historical	Lime Rock Historical	West Texas Acquisition Properties Historical	Pro Forma Adjustments	Pro Forma as Adjusted
			(in thousands)			
Future cash inflows	$ 4,604,241	$ 333,836	$ 206,964	$ 336,784	$ —	$ 5,481,825
Future development costs	(517,075)	(10,118)	(5,383)	(24,732)	—	(557,308)
Future production costs	(1,125,291)	(136,274)	(84,021)	(136,020)	—	(1,481,606)
Future income tax expenses	(674,260)	(2,337)	—	(2,357)	(55,417)	(734,371)
Future net cash flows	2,287,615	185,107	117,560	173,675	(55,417)	2,708,540
10% discount to reflect timing of cash flows	(1,311,976)	(77,845)	(46,700)	(83,437)	23,862	(1,496,096)
Standardized measure of discounted future net cash flows	$ 975,639	$ 107,262	$ 70,860	$ 90,238	$ (31,555)	$ 1,212,444

The changes in Diamondback's pro forma standardized measure of discounted estimated future net cash flows were as follows for 2013:

	Diamondback Historical	Henry Group Historical	Lime Rock Historical	West Texas Acquisition Properties Historical	Pro Forma Adjustments	Pro Forma as Adjusted
			(in thousands)			
Standardized measure of discounted future net cash flows at the beginning of the period	$ 367,220	$ 100,858	$ 78,080	$ 101,943	$ —	$ 648,101
Sales of oil and natural gas, net of production costs	(173,946)	(31,706)	(20,946)	(28,822)	—	(255,420)
Purchase of minerals in place	305,109	—	—	—	—	305,109
Extensions and discoveries, net of future development costs	552,450	186	—	—	—	552,636
Previously estimated development costs incurred during the period	76,631	16,105	12,085	—	—	104,821
Net changes in prices and production costs	51,828	13,990	1,443	6,719	—	73,980
Changes in estimated future development costs	(5,822)	389	336	—	—	(5,097)
Revisions of previous quantity estimates	(126,993)	9,685	(4,357)	—	—	(121,665)
Accretion of discount	57,988	10,197	7,907	10,194	—	86,286
Net change in income taxes	(168,570)	(78)	113	160	(31,555)	(199,930)
Net changes in timing of production and other	39,744	(12,364)	(3,801)	44	—	23,623
Standardized measure of discounted future net cash flows at the end of the period	$ 975,639	$ 107,262	$ 70,860	$ 90,238	$ (31,555)	$ 1,212,444

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Diamondback Energy, Inc.

We have audited the accompanying consolidated balance sheets of Diamondback Energy, Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related combined consolidated statements of operations, stockholders'/members' equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the combined consolidated financial statements referred to above present fairly, in all material respects, the financial position of Diamondback Energy, Inc. and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2014 (not included herein) expressed an unqualified opinion.

/s/ GRANT THORNTON LLP

Oklahoma City, Oklahoma
February 19, 2014 (except for Note 18, as to which the date is September 12, 2014)

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets

	December 31,	
	2013	2012
Assets	(In thousands, except par values and share data)	
Current assets:		
Cash and cash equivalents	$ 15,555	$ 26,358
Accounts receivable:		
Joint interest and other	14,437	5,959
Oil and natural gas sales	23,533	8,081
Related party	1,303	772
Inventories	5,631	6,195
Deferred income taxes	112	1,857
Derivative instruments	213	—
Prepaid expenses and other	1,184	1,053
Total current assets	61,968	50,275
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($369,561 and $121,245 excluded from amortization at December 31, 2013 and December 31, 2012, respectively)	1,648,360	697,742
Pipeline and gas gathering assets	6,142	—
Other property and equipment	4,071	2,337
Accumulated depletion, depreciation, amortization and impairment	(212,236)	(145,837)
	1,446,337	554,242
Derivative instruments	218	—
Other assets	13,091	2,184
Total assets	$ 1,521,614	$ 606,701
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$ 2,679	$ 12,141
Accounts payable-related party	17	18,813
Accrued capital expenditures	74,649	29,397
Other accrued liabilities	34,750	10,649
Revenues and royalties payable	9,225	3,270
Derivative instruments	—	4,817
Note payable-short term	—	145
Total current liabilities	121,320	79,232
Long-term debt	460,000	193
Derivative instruments	—	388
Asset retirement obligations	2,989	2,125
Deferred income taxes	91,764	62,695
Total liabilities	676,073	144,633
Commitments and contingencies (Note 14)		
Stockholders' equity:		
Common stock, $0.01 par value, 100,000,000 shares authorized, 47,106,216 issued and outstanding at December 31, 2013; 36,986,532 issued and outstanding at December 31, 2012	471	370
Additional paid-in capital	842,557	513,772
Retained earnings (accumulated deficit)	2,513	(52,074)
Total stockholders' equity	845,541	462,068
Total liabilities and stockholders' equity	$ 1,521,614	$ 606,701

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Operations

	Year Ended December 31,		
	2013	**2012**	**2011**
	(In thousands, except per share amounts)		
Revenues:			
Oil sales	$ 188,753	$ 65,704	$ 2,582
Oil sales - related party	—	—	38,873
Natural gas sales	3,715	1,369	1,061
Natural gas sales - related party	2,534	1,010	586
Natural gas liquid sales	8,304	3,839	3,169
Natural gas liquid sales - related party	4,696	3,040	1,604
Oil and natural gas services - related party	—	—	1,491
Total revenues	208,002	74,962	49,366
Costs and expenses:			
Lease operating expenses	19,991	14,231	7,804
Lease operating expenses - related party	1,166	1,016	2,127
Production and ad valorem taxes	12,399	4,950	1,240
Production and ad valorem taxes - related party	500	287	1,792
Gathering and transportation	237	124	53
Gathering and transportation - related party	681	300	149
Oil and natural gas services	—	—	1,207
Oil and natural gas services - related party	—	—	526
Depreciation, depletion and amortization	66,597	26,273	15,601
General and administrative expenses (including non-cash stock based compensation, net of capitalized amounts, of $1,752, $2,477 and $438 for the years ended December 31, 2013, 2012 and 2011, respectively)	9,870	9,178	495
General and administrative expenses - related party	1,166	1,198	3,160
Asset retirement obligation accretion expense	201	98	65
Total costs and expenses	112,808	57,655	34,219
Income from operations	95,194	17,307	15,147
Other income (expense)			
Interest income	1	3	11
Interest expense	(8,059)	(3,610)	(2,528)
Other income - related party	1,077	2,132	—
Gain (loss) on derivative instruments, net	(1,872)	2,617	(13,009)
Loss from equity investment	—	(67)	(7)
Total other income (expense), net	(8,853)	1,075	(15,533)
Income (loss) before income taxes	86,341	18,382	(386)
Provision for income taxes			
Current	191	—	—
Deferred	31,563	54,903	—
Net income (loss)	$ 54,587	$ (36,521)	$ (386)
Earnings per common share			
Basic	$ 1.30		
Diluted	$ 1.29		
Weighted average common shares outstanding			
Basic	42,015		
Diluted	42,255		

See accompanying notes to combined consolidated financial statements.

	Year Ended December 31, 2012	
	(In thousands, except per share amounts)	
Pro forma information (unaudited)		
Income before income taxes, as reported	$	18,382
Pro forma provision for income taxes		6,553
Pro forma net income	$	11,829
Pro forma earnings per common share		
Basic	$	0.60
Diluted	$	0.60
Pro forma weighted average common shares outstanding		
Basic		19,721
Diluted		19,724

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity/Members' Equity

	Member's Equity	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings/ (Accumulated Deficit)	Total
				(In thousands)		
Balance, December 31, 2010	$ 115,362	—	$ —	$ —	$ —	$ 115,362
Contributions	13,517	—	—	—	—	13,517
Equity based compensation	544	—	—	—	—	544
Net loss	(386)	—	—	—	—	(386)
Balance December 31, 2011	129,037	—	—	—	—	129,037
Contributions	4,008	—	—	—	—	4,008
Distributions of equity method investments	(10,504)	—	—	—	—	(10,504)
Equity based compensation	873	—	—	—	—	873
Earnings prior to merger	15,553	—	—	—	—	15,553
Common shares issued upon Merger	(138,967)	14,697	147	138,820	—	—
Common shares issued upon acquisition of Gulfport properties	—	7,914	79	138,417	—	138,496
Common shares issued at initial public offering, net of offering costs	—	14,375	144	234,000	—	234,144
Stock based compensation	—	—	—	2,535	—	2,535
Net loss subsequent to merger	—	—	—	—	(52,074)	(52,074)
Balance December 31, 2012	—	36,986	370	513,772	(52,074)	462,068
Stock based compensation	—	—	—	2,724	—	2,724
Tax benefits related to stock-based compensation	—	—	—	749	—	749
Common shares issued in public offering, net of offering costs	—	9,775	98	321,814	—	321,912
Exercise of stock options and vesting of restricted stock units	—	345	3	3,498	—	3,501
Net income	—	—	—	—	54,587	54,587
Balance December 31, 2013	$ —	47,106	$ 471	$ 842,557	$ 2,513	$ 845,541

See accompanying notes to combined consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Combined Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Cash flows from operating activities:			
Net income (loss)	$ 54,587	$ (36,521)	$ (386)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Provision for deferred income taxes	31,563	54,903	—
Excess tax benefit from stock-based compensation	(749)	—	—
Asset retirement obligation accretion expense	201	98	65
Depreciation, depletion, and amortization	66,597	26,273	16,104
Amortization of debt issuance costs	1,018	494	250
Change in fair value of derivative instruments	(5,346)	(2,617)	13,009
Loss from equity investment	—	67	—
Equity based compensation expense	1,752	3,482	544
Gain on sale of assets	(39)	(37)	(23)
Changes in operating assets and liabilities:			
Accounts receivable	(19,973)	(5,036)	(1,547)
Accounts receivable-related party	(532)	6,096	(4,133)
Inventories	554	(639)	(872)
Prepaid expenses and other	(271)	(606)	(202)
Accounts payable and accrued liabilities	20,588	7,151	2,656
Accounts payable and accrued liabilities-related party	(128)	(1,218)	830
Revenues and royalties payable	5,955	105	2,666
Revenues and royalties payable-related party	—	(2,303)	2,037
Net cash provided by operating activities	155,777	49,692	30,998
Cash flows from investing activities:			
Additions to oil and natural gas properties	(278,809)	(90,415)	(58,160)
Additions to oil and natural gas properties-related party	(13,777)	(9,675)	(22,014)
Acquisition of Gulfport properties	(18,550)	(63,590)	—
Acquisition of mineral interests	(444,083)	—	—
Acquisition of leasehold interests	(177,343)	(11,707)	—
Additions to pipeline and gas gathering assets	(5,127)	—	—
Purchase of other property and equipment	(2,234)	(1,102)	(7,065)
Proceeds from sale of property and equipment	72	48	55
Settlement of non-hedge derivative instruments	(289)	(8,963)	(4,127)
Receipt on derivative margins	—	2,326	4,203
Deconsolidation of Bison	—	—	(10)
Proceeds from sale of membership interest in equity investment	—	—	6,010
Net cash used in investing activities	(940,140)	(183,078)	(81,108)
Cash flows from financing activities:			
Proceeds from borrowings on credit facility	59,000	15,000	40,233
Repayment on credit facility	(49,000)	(100,000)	—
Proceeds from senior notes	450,000	—	—
Proceeds from note payable - related party	—	30,000	—
Payment of note payable - related party	—	(30,050)	—
Debt issuance costs	(12,361)	(450)	(770)
Public offering costs	(1,009)	(2,887)	(30)
Proceeds from public offering	322,680	237,164	—

Exercise of stock options	3,501	—	—
Excess tax benefits of stock-based compensation	749	—	—
Contributions by members	—	4,008	13,517
Net cash provided by financing activities	773,560	152,785	52,950
Net increase (decrease) in cash and cash equivalents	(10,803)	19,399	2,840
Cash and cash equivalents at beginning of period	26,358	6,959	4,119
Cash and cash equivalents at end of period	$ 15,555	$ 26,358	$ 6,959

	Year Ended December 31,		
	2013	**2012**	**2011**
	(In thousands)		
Supplemental disclosure of cash flow information:			
Interest paid, net of capitalized interest	$ 404	$ 3,017	$ 2,265
Supplemental disclosure of non-cash transactions:			
Asset retirement obligation incurred	$ 226	$ 386	$ 297
Asset retirement obligation acquired	$ 471	$ 562	$ —
Distribution of equity method investments	$ —	$ 10,504	$ —
Note payable exchanged for equipment	$ —	$ 411	$ —
Common stock issued as a result of the Gulfport transaction	$ —	$ 138,496	$ —
Post-closing adjustment payable as a result of the Gulfport transaction	$ —	$ 18,550	$ —

See accompanying notes to combined consolidated financial statements.

1. ORGANIZATION

Diamondback Energy, Inc. ("Diamondback" or the "Company") together with its subsidiaries, is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Diamondback was incorporated in Delaware on December 30, 2011, and did not conduct any material business operations until October 11, 2012 when Diamondback merged with its parent entity, Diamondback Energy LLC, with Diamondback continuing as the surviving entity (the "Merger"). Prior to the Merger, Diamondback Energy LLC was a holding company and did not conduct any material business operations other than its ownership of Diamondback's common stock and the membership interests in Diamondback O&G LLC (formerly known as Windsor Permian LLC, or "Windsor Permian"). As a result of the Merger, Windsor Permian became a wholly-owned subsidiary of Diamondback. Also on October 11, 2012, Wexford Capital LP ("Wexford"), our equity sponsor, caused all of the outstanding equity interests in Windsor UT LLC ("Windsor UT") to be contributed to Windsor Permian prior to the Merger in a transaction referred to as the "Windsor UT Contribution". The Windsor UT Contribution was treated as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests. The operations of Windsor Permian and Windsor UT, as limited liability companies, were not subject to federal income taxes. On the date of the Merger, a corresponding "first day" tax expense to net income from continuing operations was recorded to establish a net deferred tax liability for differences between the tax and book basis of Diamondback's assets and liabilities. This charge was $54,142. The Company refers to the historical results of Windsor Permian and Windsor UT prior to October 11, 2012 as the "Predecessors".

The subsidiaries of Diamondback, as of December 31, 2013, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, and Viper Energy Partners LLC, a Delaware limited liability company. The subsidiaries are all wholly owned.

Immediately after the Merger on October 11, 2012, Diamondback acquired from Gulfport Energy Corporation ("Gulfport") all of its oil and natural gas interests in the Permian Basin (the "Gulfport properties") in exchange for shares of Diamondback common stock and a promissory note in a transaction referred to as the "Gulfport transaction". The Gulfport transaction was treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets and liabilities recognized at fair value on the date of transfer. See Note 3—Acquisitions for information regarding the acquisition.

On October 17, 2012, the Company completed its initial public offering ("IPO") of 14,375 shares of common stock, which included 1,875 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $17.50 per share and the Company received net proceeds of approximately $234,100 from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In the first quarter of 2013, Windsor UT merged with and into Windsor Permian and Windsor Permian, the surviving entity in the merger, was renamed Diamondback O&G LLC ("Diamondback O&G").

On May 21, 2013, the Company completed an underwritten primary public offering of 5,175 shares of common stock, which included 675 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $29.25 per share and the Company received net proceeds of approximately $144,439 from the sale of these shares of common stock, after offering expenses and underwriting discounts and commissions.

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000 shares of the Company's common stock and, on July 5, 2013, the underwriters purchased an additional 869 shares of the Company's common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at $34.75 per share and the selling stockholders received all proceeds from this offering.

In August 2013, the Company completed an underwritten public offering of 4,600 shares of common stock, which included 600 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold the public at $40.25 per share and the Company received net proceeds of approximately $177,500 from the sale of these shares of common stock, after offering expenses and underwriting discounts and commissions.

In September 2013, the Company completed an offering of $450,000 principal amount of our 7.625% Senior Notes due 2021. See Note 7—Debt.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. As discussed above, the Windsor UT Contribution was accounted for as a transaction between entities under common control. Thus, the accompanying combined consolidated financial statements and related notes of the Company have been retrospectively adjusted to include the historical results of Windsor UT at historical carrying values and its operations prior to October 11, 2012, the effective date of the Windsor UT Contribution. The accompanying financial statements and related notes presented herein represent the combined results of operations and cash flows of the Predecessors through October 11, 2012, and the Company and its wholly-owned subsidiaries consolidated financial position, results of operations, cash flows and equity subsequent to October 11, 2012. All intercompany balances and transactions are eliminated in consolidation.

Use of Estimates

Certain amounts included in or affecting the Company's combined consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the combined consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company's disclosure of contingent assets and liabilities at the date of the combined consolidated financial statements. Actual results could differ from those estimates.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

Reclassifications

The Company has reclassified certain prior year amounts to conform with the current year's presentation. The Company has reclassified ad valorem taxes from lease operating expenses to production and ad valorem taxes.

Cash and Cash Equivalents

The Company considers all highly liquid investments purchased with a maturity of three months or less and money market funds to be cash equivalents. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date.

Accounts receivable are stated at amounts due from joint interest owners or purchasers, net of an allowance for doubtful accounts when the Company believes collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due.

The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2013 or December 31, 2012.

Derivative Instruments

The Company is required to recognize its derivative instruments on the consolidated balance sheets as assets or liabilities at fair value with such amounts classified as current or long-term based on their anticipated settlement dates. The accounting for the changes in fair value of a derivative depends on the intended use of the derivative and resulting designation. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash change in fair value on derivative instruments in the combined consolidated statements of operations.

Fair Value of Financial Instruments

The Company's financial instruments consist of cash and cash equivalents, receivables, payables, derivatives, notes payable and senior notes. The carrying amount of cash and cash equivalents, receivables and payables approximates fair value because of the short-term nature of the instruments. The fair value of the revolving credit facility approximates its carrying value based on the borrowing rates currently available to the Company for bank loans with similar terms and maturities. The note payable is carried at cost, which approximates fair value due to the nature of the instrument and relatively short maturity. The fair value of the senior notes are determined using quoted market prices. Derivatives are recorded at fair value (see Note 13—Fair Value Measurements).

Oil and Natural Gas Properties

The Company accounts for its oil and natural gas producing activities using the full cost method of accounting. Accordingly, all costs incurred in the acquisition, exploration and development of proved oil and natural gas properties, including the costs of abandoned properties, dry holes, geophysical costs and annual lease rentals are capitalized. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities are charged to expense as they are incurred. Sales or other dispositions of oil and natural gas properties are accounted for as adjustments to capitalized costs, with no gain or loss recorded unless the ratio of cost to proved reserves would significantly change. Any income from services provided by subsidiaries to working interest owners of properties in which the Company also owns an interest, to the extent they exceed related costs incurred, are accounted for as reductions of capitalized costs of oil and natural gas properties proportionate to the Company's investment in the subsidiary (see Note 6—Equity Method Investments). Depletion of evaluated oil and natural gas properties is computed on the units of production method, whereby capitalized costs plus estimated future development costs are amortized over total proved reserves. The average depletion rate per barrel equivalent unit of production was $24.63, $23.90 and $25.41 for the years ended December 31, 2013, 2012 and 2011, respectively. Depreciation, depletion and amortization expense for oil and natural gas properties was $65,821, $25,772 and $15,377 for the years ended December 31, 2013, 2012 and 2011, respectively.

Under the full cost method of accounting, the net book value of oil and natural gas properties, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling limitation is the estimated after-tax future net cash flows from proved oil and natural gas reserves, discounted at 10%. Estimated future net cash flows exclude future cash flows associated with settling accrued asset retirement obligations. Estimated future net cash flows are calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months, held flat for the life of the production. Any excess of the net book value of proved oil and natural gas properties, less related deferred income taxes, over the ceiling is charged to expense. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2013, 2012 or 2011.

Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The Company assesses all items classified as unevaluated property on an annual basis for possible impairment. The Company assesses properties on an individual basis or as a group if properties are individually insignificant. The assessment includes consideration of the following factors, among others: intent to drill; remaining lease term; geological and geophysical evaluations; drilling results and activity; the assignment of proved reserves; and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to amortization.

(Amounts in thousands, except per share, per BOE and acreage amounts)

Other Property and Equipment

Other property and equipment is recorded at cost. The Company expenses maintenance and repairs in the period incurred. Upon retirements or disposition of assets, the cost and related accumulated depreciation are removed from the combined consolidated balance sheet with the resulting gains or losses, if any, reflected in operations. Depreciation of other property and equipment is computed using the straight line method over their estimated useful lives, which range from three to fifteen years. Depreciation expense was $776, $501 and $727 for the years ended December 31, 2013, 2012 and 2011, respectively.

Asset Retirement Obligations

The Company measures the future cost to retire its tangible long-lived assets and recognizes such cost as a liability for legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction or normal operation of a long-lived asset.

The Company records a liability relating to the retirement and removal of all assets used in their businesses. Asset retirement obligations represent the future abandonment costs of tangible assets, namely wells. The fair value of a liability for an asset's retirement obligation is recorded in the period in which it is incurred if a reasonable estimate of fair value can be made and the corresponding cost is capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, the difference is recorded in oil and natural gas properties.

Impairment of Long-Lived Assets

Other property and equipment used in operations are reviewed whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss is recognized only if the carrying amount of a long-lived asset is not recoverable from its estimated future undiscounted cash flows. An impairment loss is the difference between the carrying amount and fair value of the asset. The Company had no such impairment losses for the years ended December 31, 2013, 2012 or 2011.

Capitalized Interest

The Company capitalizes interest on expenditures made in connection with exploration and development projects that are not subject to current amortization. Interest is capitalized only for the period that activities are in progress to bring these projects to their intended use. Capitalized interest cannot exceed gross interest expense. The Company capitalized interest of $3,951 for the year ended December 31, 2013. During the years ended December 31, 2012 and 2011, the Company did not capitalize any interest expense.

Inventories

Inventories are stated at the lower of cost or market and consist of the following:

	December 31,	
	2013	**2012**
Tubular goods and equipment	$ 5,631	$ 5,725
Crude oil	—	470
	$ 5,631	$ 6,195

The Company's tubular goods and equipment is primarily comprised of oil and natural gas drilling or repair items such as tubing, casing and pumping units. The inventory is primarily acquired for use in future drilling or repair operations and is carried at lower of cost or market. “Market”, in the context of inventory valuation, represents net realizable value, which is the amount that the Company is allowed to bill to the joint accounts under joint operating agreements to which the Company is a party. As of December 31, 2013, the Company estimated that all of its tubular goods and equipment will be utilized within one year.

(Amounts in thousands, except per share, per BOE and acreage amounts)

Debt Issuance Costs

Other assets included capitalized costs of $12,458 and $1,115, net of accumulated amortization of $1,798 and $782, as of December 31, 2013 and 2012, respectively. The increase in 2013 related primarily to the $10,376 of costs incurred upon the issuance of the 7.625% Senior Notes due 2021. The costs associated with the Senior Notes are being amortized over the term of the Senior Notes using the effective interest method. The costs associated with our credit facility are being amortized over the term of the facility.

Other Accrued Liabilities

Other accrued liabilities consist of the following:

	December 31,	
	2013	2012
Prepaid drilling liability	$ 16,491	$ 4,540
Interest payable	9,918	—
Lease operating expense payable	4,538	4,737
Current portion of asset retirement obligations	40	20
Other	3,763	1,352
	$ 34,750	$ 10,649

Revenue and Royalties Payable

For certain oil and natural gas properties, where the Company serves as operator, the Company receives production proceeds from the purchaser and further distributes such amounts to other revenue and royalty owners. Production proceeds applicable to other revenue and royalty owners are reflected as revenue and royalties payable in the accompanying combined consolidated balance sheets. The Company recognizes revenue for only its net revenue interest in oil and natural gas properties.

Revenue Recognition

Oil and natural gas revenues are recorded when title passes to the purchaser, net of royalty interests, discounts and allowances, as applicable. The Company accounts for oil and natural gas production imbalances using the sales method, whereby a liability is recorded when the Company’s overtake volumes exceed its estimated remaining recoverable reserves. No receivables are recorded for those wells where the Company has taken less than its ownership share of production. The Company did not have any gas imbalances as of December 31, 2013 or December 31, 2012. Revenues from oil and natural gas services are recognized as services are provided.

Investments

Equity investments in which the Company exercises significant influence but does not control are accounted for using the equity method. Under the equity method, generally the Company’s share of investees’ earnings or loss is recognized in the statement of operations. The Company reviews its investments to determine if a loss in value which is other than a temporary decline has occurred. If such loss has occurred, the Company would recognize an impairment provision. There was no impairment for the Company’s equity investments for the years ended December 31, 2013 and 2012. For additional information on the Company’s investments, see Note 6—Equity Method Investments.

Accounting for Stock-Based Compensation

The Company grants various types of stock-based awards including stock options and restricted stock units. These plans and related accounting policies are defined and described more fully in Note 9—Stock and Equity Based Compensation. Stock compensation awards are measured at fair value on the date of grant and are expensed, net of estimated forfeitures, over the required service period.

Concentrations

The Company is subject to risk resulting from the concentration of its crude oil and natural gas sales and receivables with several significant purchasers. For the year ended December 31, 2013 two purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (37%); and Shell Trading (US) Company (37%). For the year ended December 31, 2012, three purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (53%); Occidental Energy Marketing, Inc. (16%); and Andrews Oil Buyers, Inc. (10%). For the year ended December 31, 2011, Windsor Midstream LLC, a related party, accounted for 79% of the Company's revenue. The Company does not require collateral and does not believe the loss of any single purchaser would materially impact its operating results, as crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

Environmental Compliance and Remediation

Environmental compliance and remediation costs, including ongoing maintenance and monitoring, are expensed as incurred. Liabilities are accrued when environmental assessments and remediation are probable, and the costs can be reasonably estimated.

Income Taxes

Diamondback uses the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities and (2) operating loss and tax credit carryforwards. Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period the rate change is enacted. A valuation allowance is provided for deferred tax assets when it is more likely than not the deferred tax assets will not be realized.

The Company and the Predecessor are subject to margin tax in the state of Texas. During the years ended December 31, 2013, 2012 and 2011, there was no margin tax expense. The Company's 2009, 2010, 2011, 2012 and 2013 federal income tax and state margin tax returns remain open to examination by tax authorities. As of December 31, 2013 and December 31, 2012, the Company had no unrecognized tax benefits that would have a material impact on the effective rate. The Company is continuing its practice of recognizing interest and penalties related to income tax matters as interest expense and general and administrative expenses, respectively. During the years ended December 31, 2013, 2012 and 2011, there was no interest or penalties associated with uncertain tax positions recognized in the Company's combined consolidated financial statements.

Unaudited Pro Forma Income Taxes

Diamondback was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback is a C-Corporation under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and the Predecessors were subject to income taxes since December 31, 2011. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

Unaudited Pro Forma Earnings per Share

The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the Merger were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur.

(Amounts in thousands, except per share, per BOE and acreage amounts)

3. ACQUISITIONS

2013 Activity

In September 2013, the Company completed two separate acquisitions of additional leasehold interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $165,000, subject to certain adjustments. The first of these acquisitions closed on September 4, 2013, when the Company acquired certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres. The second of these acquisitions closed on September 26, 2013, when the Company acquired certain assets located primarily in southwestern Dawson County, Texas, consisting of a 71% working interest (55% net revenue interest) in 9,390 gross (6,638 net) acres. These acquisitions were funded with a portion of the net proceeds from the August 2013 equity offering discussed in Note 1—Organization.

On September 19, 2013, the Company completed the acquisition of the mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin. The mineral interests entitle the Company to receive an average 19.5% royalty interest on all production from this acreage with no additional future capital or operating expense required. The acquisition was accounted for as an acquisition of assets. The $440,000 purchase price was funded with the net proceeds of the Company's offering of Senior Notes discussed in Note 7—Debt.

2012 Activity

On October 11, 2012, the Company completed the acquisition of Gulfport's oil and natural gas interests in the Permian Basin. The acquisition was accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value.

The acquisition-date fair value of the consideration transferred totaled $220,636, which consisted of the following:

Common Stock (7,914 shares)	$	138,496
Promissory note paid in full from IPO proceeds		63,590
Closing adjustment payable		18,550
Total	$	220,636

The fair value of the 7,914 common shares issued was determined based on the IPO pricing of $17.50 per common share on October 11, 2012. The closing adjustment payable balance is a result of the working capital adjustment.

The following table summarizes the estimated fair values of the assets acquired and liabilities assumed at the acquisition date. As shown above, consideration transferred in the transaction was $220,636, resulting in no goodwill or bargain purchase gain.

Proved oil and natural gas properties	$	115,760
Unevaluated oil and natural gas properties		111,373
Asset retirement obligations		(562)
Deferred income tax liability		(5,935)
Total fair value of net assets	$	220,636

(Amounts in thousands, except per share, per BOE and acreage amounts)

The Company has included in its combined consolidated statements of operations revenues of $7,353 and direct operating expenses of $2,260 for the period from October 11, 2012 to December 31, 2012 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion. The following unaudited summary pro forma combined consolidated statements of operations data of Diamondback for the years ended December 31, 2012 and 2011 have been prepared to give effect to the acquisition as if it had occurred on January 1, 2011. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisition occurred on January 1, 2011. The pro forma data also necessarily exclude various operation expenses related to the Gulfport properties and such financial statements should not be viewed as indicative of operations in future periods.

	Pro Forma (Unaudited) Year Ended December 31,	
	2012	2011
Pro forma total revenues	$ 97,455	$ 72,418
Pro forma income from operations	24,064	23,189
Pro forma net income	(29,764)	7,666 (1)

(1) For 2011, this amount does not include a pro forma income tax provision relating to becoming subject to income taxes as a result of the Merger.

4. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	December 31,	
	2013	2012
Oil and natural gas properties:		
Subject to depletion	$ 1,278,799	$ 576,497
Not subject to depletion-acquisition costs		
Incurred in 2013	279,353	—
Incurred in 2012	87,252	117,395
Incurred in 2011	1,598	1,670
Incurred in 2010	1,358	1,647
Incurred in 2009	—	533
Total not subject to depletion	369,561	121,245
Gross oil and natural gas properties	1,648,360	697,742
Less accumulated depreciation, depletion, amortization and impairment	(210,837)	(145,102)
Oil and natural gas properties, net	1,437,523	552,640
Pipeline and gas gathering assets	6,142	—
Other property and equipment	4,071	2,337
Less accumulated depreciation	(1,399)	(735)
Other property and equipment, net	2,672	1,602
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 1,446,337	$ 554,242

Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately $5,348, $4,872 and $871 for the years ended December 31, 2013, 2012 and 2011, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years.

(Amounts in thousands, except per share, per BOE and acreage amounts)

5. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company’s asset retirement obligation liability for the following periods:

	Year Ended December 31,		
	2013	2012	2011
Asset retirement obligation, beginning of period	$ 2,145	$ 1,104	$ 742
Additional liability incurred	226	201	297
Liabilities acquired	471	562	—
Liabilities settled	(14)	(5)	—
Accretion expense	201	98	65
Revisions in estimated liabilities	—	185	—
Asset retirement obligation, end of period	3,029	2,145	1,104
Less current portion	40	20	—
Asset retirement obligations - long-term	$ 2,989	$ 2,125	$ 1,104

The Company’s asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

6. EQUITY METHOD INVESTMENTS

Bison Drilling and Field Services LLC

On November 15, 2010, the Company formed a wholly owned subsidiary, Bison Drilling and Field Services LLC (“Bison”), formerly known as Windsor Drilling LLC. In addition, on March 2, 2010, the Company formed a wholly owned subsidiary, West Texas Field Services LLC, which, on January 1, 2011, contributed all of its assets and liabilities to Bison and West Texas Field Services LLC was subsequently dissolved on June 12, 2012. Bison owns and operates drilling rigs and various oil and natural gas well servicing equipment.

Beginning on March 31, 2011, various related party investors contributed capital to Bison diluting the Company’s ownership interest. As of June 15, 2012, the Company distributed its remaining 22% interest in Bison to an entity which is controlled and managed by Wexford. As the transaction was between entities under common control, the Company recognized the distribution of $6,437 as an equity transaction. Bison continues to be a related party with the Company.

Muskie Holdings LLC

During 2011, the Company paid approximately $4,200 for land and various other capital items related to the land. On October 7, 2011, the Company contributed these assets to a newly formed entity, Muskie Holdings LLC (“Muskie”), a Delaware limited liability company now known as Muskie Proppant LLC, for a 48.6% equity interest. Through additional contributions to Muskie from a related party and various Wexford portfolio companies, the Company’s interest in Muskie decreased to 33% as of June 15, 2012. Muskie generated a loss during the period from January 1, 2012 through June 15, 2012 and the Company recorded its share of this loss.

As of June 15, 2012, the Company distributed its remaining interest in Muskie to an entity which is controlled and managed by Wexford. As the transaction was between entities under common control, the Company recognized the distribution of $4,067 as an equity transaction. Muskie continues to be a related party with the Company.

(Amounts in thousands, except per share, per BOE and acreage amounts)

7. DEBT

Long-term debt consisted of the following:

	December 31,	
	2013	2012
Revolving credit facility	$ 10,000	$ —
7.625 % Senior Notes due 2021	450,000	—
Note Payable	—	338
Total long-term debt	460,000	338
Less current portion of long-term debt	—	(145)
Long-term debt, net of current portion	$ 460,000	$ 193

Senior Notes

On September 18, 2013, the Company completed an offering of $450,000 in aggregate principal amount of 7.625% senior unsecured notes due 2021 (the “Senior Notes”). The Senior Notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014 and will mature on October 1, 2021. The Senior Notes are fully and unconditionally guaranteed by the Company’s subsidiaries. The net proceeds from the Senior Notes were used to fund the acquisition of mineral interests underlying approximately 15,000 gross (12,500 net) acres in Midland County, Texas in the Permian Basin.

The Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee (the “Indenture”). The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company’s ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of subsidiaries, agree to payment restrictions affecting the Company’s restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of the Company’s subsidiaries as unrestricted subsidiaries. If the Company experiences certain kinds of changes of control or if it sells certain of its assets, holders of the Senior Notes may have the right to require the Company to repurchase their Senior Notes.

The Company will have the option to redeem the Senior Notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, the Company may redeem all or a part of the Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a “make-whole” premium at the redemption date. Furthermore, before October 1, 2016, the Company may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the Senior Notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the Senior Notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

In connection with the issuance of the Senior Notes, the Company and the subsidiary guarantors entered into a Registration Rights Agreement (the “Registration Rights Agreement”) with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the Senior Notes for a new issue of substantially identical debt securities registered under the Securities Act. Under the Registration Rights Agreement, the Company also agreed to use its commercially reasonable efforts to cause the exchange offer registration statement to become effective within 360 days after the issue date of the Senior Notes and to consummate the exchange offer 30 days after effectiveness. The Company may be required to file a shelf registration statement to cover resales of the Senior Notes under certain circumstances. If the Company fails to satisfy certain of its obligations under the Registration Rights Agreement, the

(Amounts in thousands, except per share, per BOE and acreage amounts)

Company agreed to pay additional interest to the holders of the Senior Notes as specified in the Registration Rights Agreement.

Credit Facility-Wells Fargo Bank

On October 15, 2010, the Company entered into a secured revolving credit agreement with BNP Paribas, or BNP, as the administrative agent, sole book runner and lead arranger. On May 10, 2012, the revolving credit agreement was amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, as administrative agent for the lenders. The credit agreement was amended and restated as of July 24, 2012 and again as of November 1, 2013. The credit agreement, as so amended and restated, provides for a revolving credit facility in the maximum amount of $600,000, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of December 31, 2013, the borrowing base was $225,000. As of December 31, 2013, the Company had outstanding borrowings of $10,000 which bore a weighted average interest rate of 1.67%.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is based on the prime rate or LIBOR plus margins ranging from 0.50% for prime-based loans and 1.50% for LIBOR loans to 1.50% for prime-based loans and 2.50% for LIBOR loans, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of November 1, 2018. The loan is secured by substantially all of the assets of the Company and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

EBITDAX will be annualized beginning with the quarter ended September 30, 2013 and ending with the quarter ending March 31, 2014.

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750,000 in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of December 31, 2013, the Company had $450,000 of senior notes outstanding.

As of December 31, 2013 and December 31, 2012, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Note Payable

The Company entered into an installment payment contract with EMC Corporation for the purchase of computer equipment. The contract is payable in equal installments over a period of 36 months. The Company repaid all outstanding borrowings under this note in 2013 and, as of December 31, 2013, had no amounts outstanding under this note. As of December 31, 2012, the Company had amounts outstanding under this note of $338.

(Amounts in thousands, except per share, per BOE and acreage amounts)

Subordinated Note

Effective May 14, 2012, the Company issued a subordinated note to an affiliate of Wexford pursuant to which, as amended, the Wexford affiliate could, from time to time, advance up to an aggregate of $45,000. These advances were solely at the lender's discretion and neither Wexford nor any of its affiliates had any commitment or obligation to provide further capital support to the Company. The note bore interest at a rate equal to LIBOR plus 0.28% or 8% per annum, whichever was lower. Interest was due quarterly in arrears beginning on July 1, 2012. Interest payments were payable in kind by adding such amounts to the principal balance of the note. The unpaid principal balance and all accrued interest on the note was due and payable in full on January 31, 2015 or the earlier completion of an initial public offering. Any indebtedness evidenced by this note was subordinate in the right of payment to any indebtedness outstanding under the Company's revolving credit facility. Prior to the completion of the IPO, there was $30,050 in aggregate principal and interest outstanding under this note. In connection with the IPO, the Company repaid all outstanding borrowings under the subordinated note and the subordinated note was canceled.

Interest expense

The following amounts have been incurred and charged to interest expense for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Cash payments for interest	$ 404	$ 3,017	$ 2,265
Amortization of debt issuance costs	1,018	494	250
Accrued interest related to the Senior Notes	9,913	—	—
Change in accrued interest and other	675	99	13
Interest charges incurred	12,010	3,610	2,528
Less capitalized interest	(3,951)	—	—
Total interest expense	$ 8,059	$ 3,610	$ 2,528

8. EARNINGS PER SHARE & PRO FORMA EARNINGS PER SHARE

Earnings Per Share

The Company's basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	2013		
	Income	Shares	Per Share
	(Per share amounts in actual dollars)		
Basic:			
Net income attributable to common stock	$ 54,587	42,015	$ 1.30
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$ —	240	
Diluted:			
Net income attributable to common stock	$ 54,587	42,255	$ 1.29

(Amounts in thousands, except per share, per BOE and acreage amounts)

Pro Forma Earnings Per Share

The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the Merger were outstanding for the entire year. A reconciliation of the components of pro forma basic and diluted earnings per common share is presented in the table below:

	2012		
	Income	Shares	Per Share
	(Per share amounts in actual dollars)		
Basic:			
Pro forma net income attributable to common stock	$ 11,829	19,721	$ 0.60
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$ —	3	
Diluted:			
Pro forma net income attributable to common stock	$ 11,829	19,724	$ 0.60

9. STOCK AND EQUITY BASED COMPENSATION

On October 10, 2012, the Board of Directors approved the Diamondback Energy, Inc. 2012 Equity Incentive Plan (the "2012 Plan"), which is intended to provide eligible employees with equity-based incentives. The 2012 Plan provides for the granting of incentive stock options, nonstatutory stock options, restricted awards (restricted stock and restricted stock units), performance awards, and stock appreciation rights, or any combination of the foregoing. A total of 2,500 shares of the Company's common stock has been reserved for issuance pursuant to this plan. Previous to the 2012 Plan, each of the Company's Executive Officers was provided with an option to acquire a percentage membership interest in Windsor Permian. In connection with the IPO and the 2012 Plan, these options were canceled and replaced with the right to receive a cash payment, restricted stock units and stock options. Such grant of new awards was deemed to be a modification of old awards and was accounted for as a modification of the original awards. The modification date for these awards was October 11, 2012, which was the date the Company's IPO was priced at $17.50 per share. Eight employees were affected by this modification. As a result of the modification, incremental compensation cost of $4,588 was recognized on the modification date to recognize the portion of awards that are vested and includes cash payments of $2,813. In addition to the compensation expense recognized on the modification date, $5,866 of compensation expense will be recognized over the remaining service period and a liability of $333 was recognized ratably over one year as the Company's chief executive officer received a cash payment on the first anniversary date of the IPO. The modification did not change the original vesting or exercise periods. As a result, options vest in four substantially equal annual installments commencing on the first anniversary of the original date of grant and are exercisable for 5 years from the original date of grant.

The following table presents the effects of the equity and stock based compensation plans and related costs:

	2013	2012	2011
General and administrative expenses	$ 2,983	$ 3,757	$ 438
Stock based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	972	2,537	106
Related income tax benefit	704	930	—

Stock Options

In accordance with the 2012 Plan, the exercise price of stock options granted may not be less than the market value of the stock at the date of grant. The shares issued under the 2012 Plan will consist of new shares of Company stock. Unless otherwise specified in an agreement, options become exercisable ratably over a five-year period. However, as described above, options associated with the modification vest in 4 substantially equal annual installments and are exercisable for 5 years from the date of grant.

(Amounts in thousands, except per share, per BOE and acreage amounts)

The fair value of the stock options on the date of grant is expensed over the applicable vesting period. The Company estimates the fair values of stock options granted using a Black-Scholes option valuation model, which requires the Company to make several assumptions. The Company does not have a long history of market prices, thus the expected volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards and remaining vesting term at the modification date. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the option at the date of grant. The Company does not anticipate paying cash dividends; therefore, the expected dividend yield was assumed to be zero. All such amounts represent the weighted-average amounts for each year.

	2013	2012
Grant-date fair value	$ 6.51	$ 4.41
Expected volatility	36.9%	40.0%
Expected dividend yield	0.0%	0.0%
Expected term (in years)	3.8	3.8
Risk-free rate	0.57%	0.33%

The following table presents the Company’s stock option activity under the 2012 Plan for the year ended December 31, 2013:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (In years)	Intrinsic Value
Outstanding at December 31, 2012	850	$ 17.50		
Granted	63	$ 22.72		
Exercised	(200)	$ 17.50		
Expired/Forfeited	—	$ —		
Outstanding at December 31, 2013	713	$ 17.96	2.69	$ 24,895
Vested and Expected to vest at December 31, 2013	713	$ 17.96	2.69	$ 24,895
Exercisable at December 31, 2013	250	$ 17.50	2.11	$ 8,843

The aggregate intrinsic value of stock options that were exercised during 2013 was $5,717. As of December 31, 2013, the unrecognized compensation cost related to unvested stock options was $1,718. Such cost is expected to be recognized over a weighted-average period of 1.7 years.

Restricted Stock Awards and Units

Under the 2012 Plan, approved by the Board of Directors, the Company is authorized to issue restricted stock and restricted stock units to eligible employees. The Company estimates the fair values of restricted stock awards and units as the closing price of the Company’s common stock on the grant date of the award, which is expensed over the applicable vesting period. The following table presents a summary of the Company’s restricted stock awards and units.

(Amounts in thousands, except per share, per BOE and acreage amounts)

The following table presents the Company's restricted stock awards and units activity under the 2012 Plan for the year ended December 31, 2013:

	Restricted Stock Awards & Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2012	206	$ 17.50
Granted	11	$ 41.66
Vested	(81)	$ 18.03
Forfeited	(4)	$ 17.50
Unvested at December 31, 2013	132	$ 19.20

The aggregate fair value of restricted stock units that vested in 2013 and 2012 was $3,310 and $1,269, respectively. As of December 31, 2013, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $2,053. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

Equity-Based Compensation

During the year ended December 31, 2011, Windsor Permian granted to its executive officers options to acquire membership interests in Windsor Permian. Such options vested in four equal annual installments commencing on the first anniversary of the date of grant and were exercisable for five years from the date of grant. Summarized below are the grant dates with the total exercise prices and total fair values of the underlying options:

Grants Made During the Months Ended	Membership Interest Granted	Exercise Price	Fair Value at Date of Grant
April 2011	1.00%	$ 3,600	$ 1,453
August 2011	1.20%	6,000	1,384
September 2011	1.25%	5,900	1,533
November 2011	0.25%	1,250	288
	3.70%	$ 16,750	$ 4,658

At December 31, 2011, the intrinsic value for all outstanding options was $113 and the weighted-average remaining contractual terms were 4.6 years. Also, at December 31, 2011, no options were exercisable.

The Company accounted for such options issued using a fair-value-based method calculated on the grant-date of the award. The resulting cost was recognized on a straight-line basis over the vesting period of the entire option.

The fair value of the options issued was estimated using the Black-Scholes option-pricing model. One of the inputs to this model was the estimate of the fair value of the underlying membership interest on the date of grant. The other inputs include an estimate of the expected volatility of the membership interest, an option's expected term, the risk-free interest rate over the option's expected term, the option's exercise price and expectations regarding dividends.

Windsor Permian did not have a history of market prices for its membership interests because such interests were not publicly traded. The expected volatility was determined using the historical volatility for a peer group of companies. The expected term for options issued was determined based on the contractual term of the awards. The weighted-average risk-free interest rate was based on the daily U.S. treasury yield curve rate whose term was consistent with the expected life of the options. Windsor Permian did not anticipate paying cash dividends; therefore, the expected dividend yield was assumed to be zero.

(Amounts in thousands, except per share, per BOE and acreage amounts)

A summary of the significant assumptions used to estimate the fair value of the options to acquire membership interests during the year ended December 31, 2011 was as follows:

Expected term	5 years
Risk-free interest rate	0.96%
Expected volatility	45.5%
Expected dividend yield	0.00%

These equity-based awards were canceled and replaced with the right to receive a cash payment, restricted stock units and stock options as described in the above sections of this Note.

10. RELATED PARTY TRANSACTIONS

Administrative Services

An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. Through December 31, 2011, amounts charged to the Company included those costs directly attributable to the Company as well as indirect costs allocated to the Company. The reimbursement amount for indirect costs is determined by the affiliate's management based on estimates of time devoted to the Company. The initial term of this shared service agreement was two years. Since the expiration of such two-year period on March 1, 2010, the agreement by its terms, continued on a month-to-month basis. For the years ended December 31, 2013, 2012 and 2011, the Company incurred total costs of $207, $4,419 and $10,110, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. The expensed costs were partially offset in general and administrative expenses by overhead reimbursements of $2,548 and $1,954 for the years ended December 31, 2012 and 2011, respectively. As of December 31, 2013 and December 31, 2012, the Company owed the administrative services affiliate $17 and $13, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provides this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement is two years. Upon expiration of the initial term the agreement will continue on a month-to-month basis until canceled by either party upon thirty days prior written notice. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the years ended December 31, 2013 and 2012, the affiliate reimbursed the Company $1,077 and $2,132, respectively for services under the shared services agreement. As of December 31, 2013 and December 31, 2012, the affiliate owed the Company no amounts and $1, respectively. These amounts are included in accounts receivable-related party in the accompanying consolidated balance sheets.

Operating Services

The Company is the operator of substantially all of its properties. As operator of these properties, the Company is responsible for the daily operations, monthly operation billings and monthly revenue disbursements for the properties.

As of December 31, 2013 and December 31, 2012, amounts due from an affiliate (a greater than 5% stockholder) related to joint interest billings and included in accounts receivable-related party in the accompanying consolidated balance sheets were no amounts and $742, respectively.

Drilling Services

Bison has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company's most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. At December 31, 2013, Bison was providing drilling services to the Company using one of its rigs. This master drilling agreement is terminable by either party on 30 days prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. For the three months ended March 31, 2011, Bison was a wholly owned subsidiary and intercompany amounts were eliminated in consolidation. For the years ended December 31, 2013, 2012 and 2011 the Company incurred total costs of $13,921, $16,040 and $16,357, respectively, payable to Bison. The Company owed Bison no amounts as of December 31, 2013 and $120 as of December 31, 2012.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC (“Panther Drilling”), an entity controlled by Wexford. Panther Drilling provides directional drilling and other services. This master service agreement is terminable by either party on 30 days prior written notice, although neither party will be relieved of its respective obligations arising from work performed prior to the termination of the master service agreement. In the third quarter 2013, the Company began using Panther Drilling’s directional drilling services. For the year ended December 31, 2013, the Company incurred $176 for services performed by Panther Drilling. The Company owed Panther Drilling no amounts as of December 31, 2013.

Marketing Services

The Company entered into an agreement on March 1, 2009 with an entity under common management that purchased and received a significant portion of the Company’s oil volumes. December 1, 2011, the Company ceased all sales of its production under this agreement and effective January 1, 2012 the agreement with the affiliate was canceled. The Company’s revenues from the affiliate were $38,873 for the year ended December 31, 2011, and such amounts are included in oil sales–related party in the accompanying combined consolidated statements of operations.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC (“Coronado Midstream”), formerly known as MidMar Gas LLC, an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream, all of the gas conforming to certain quality specifications produced from certain of the Company’s Permian Basin acreage. Following the expiration of the initial ten year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days’ written notice. Under the gas purchase agreement, Coronado Midstream is obligated to pay the Company 87% of the net revenue received by Coronado Midstream for all components of the Company’s dedicated gas, including the liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at Coronado Midstream’s gas processing plant, and 94.56% of the net revenue received by Coronado Midstream from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron’s Headlee plant. The Company recognized revenues from Coronado Midstream of $7,230, $4,050 and $2,190 for the years ended December 31, 2013, 2012 and 2011, respectively. As of December 31, 2013 and December 31, 2012, Coronado Midstream owed the Company $1,303 and $6, respectively, for the Company’s portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie, an entity affiliated with Wexford, processes and sells fracking grade sand for oil and natural gas operations. The Company began purchasing sand from Muskie in March 2013. On May 16, 2013, the Company entered into a master services agreement with Muskie, pursuant to which Muskie agreed to sell custom natural sand proppant to the Company based on the Company’s requirements. The Company is not obligated to place any orders with, or accept any offers from, Muskie for sand proppant. The agreement may be terminated at the option of either party on 30 days’ notice. The Company incurred costs of $743 for the year ended December 31, 2013. As of December 31, 2013, the Company did not owe Muskie any amounts.

Midland Lease

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $214, $155 and $40 for the years ended December 31, 2013, 2012 and 2011, respectively, under this lease. In the second and third quarters of 2013, the Company amended this agreement to increase the size of the leased premises. The monthly rent under the lease increased from $13 to $15 beginning on August 1, 2013 and increased further to $25 beginning on October 1, 2013. The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $244 and $329 for the years ended December 31, 2013 and 2012, respectively, under this lease. Effective April 1, 2013, this lease was amended to increase the size of the leased premises, at which time our monthly base rent increased to $19 for the remainder of the lease term. The Company is also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises.

Advisory Services Agreement & Professional Services from Wexford

The Company entered into an advisory services agreement (the “Advisory Services Agreement”) with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $500, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on October 18, 2012, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company’s independent directors for such services as may be provided by Wexford at the Company’s request in connection with future acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company’s day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct. The Company incurred total costs of $500 and $191 for the years ended December 31, 2013 and 2012, respectively, under the Advisory Services Agreement. Wexford provides certain professional services to the Company, for which the Company incurred total costs of $119 for the year ended December 31, 2012. As of December 31, 2013 and December 31, 2012, the Company owed Wexford no amounts and $113, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets. The Company did not incur any costs for professional services from Wexford during the year ended December 31, 2011.

Secondary Offering Costs

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000 shares of the Company’s common stock and, on July 5, 2013, the underwriters purchased an additional 869 shares of the Company’s common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at $34.75 per share and the selling stockholders received all proceeds from this offering. The Company incurred costs of approximately $185 related to the secondary public offering.

On November 13, 2013, Gulfport completed an underwritten secondary public offering of 2,000 shares of the Company’s common stock that were owned by Gulfport. The shares were sold to the public at $53.46 per share and the selling stockholder received all proceeds from this offering. The Company incurred costs of approximately $53 related to the secondary public offering.

11. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. As discussed in Note 2—Summary of Significant Accounting Policies, Diamondback Energy LLC merged with and into Diamondback on October 11, 2012 and, accordingly, Diamondback has filed a consolidated return for the period October 11, 2012 through December 31, 2012. Prior to the Merger, the Predecessors were not subject to corporate income taxes. The Company is subject to corporate income taxes and the Texas margin tax.

(Amounts in thousands, except per share, per BOE and acreage amounts)

The components of the provision for income taxes for the years ended December 31, 2013 and 2012 are as follows:

	Year Ended December 31,	
	2013	**2012**
Current income tax provision:		
Federal	$ 191	$ —
State	—	—
Total current income tax provision	191	—
Deferred income tax provision:		
Federal	30,768	53,319
State	795	1,584
Total deferred income tax provision	31,563	54,903
Total provision for income taxes	$ 31,754	$ 54,903
Deferred recognized at date of Merger - change in tax status of Predecessors		54,142
Deferred as a result of operations from October 11, 2012 through December 31, 2012		761

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows:

	Year Ended December 31,	
	2013	**2012**
Income tax expense at the federal statutory rate (35%)	$ 30,231	$ 6,434
Deduction for pre-merger LLC earnings	—	(5,717)
Income tax expense relating to change in tax status	—	54,142
State income tax expense, net of federal tax benefit	517	42
Non-deductible expenses	1,006	2
Provision for income taxes	$ 31,754	$ 54,903

(Amounts in thousands, except per share, per BOE and acreage amounts)

The components of the Company's deferred tax assets and liabilities as of December 31, 2013 and 2012 are as follows:

	December 31,	
	2013	2012
Current:		
Deferred tax assets		
Derivative instruments	$ —	$ 1,857
Other	265	—
Total current deferred tax assets	265	1,857
Deferred tax liabilities		
Derivative instruments	153	—
Total current deferred tax liabilities	153	—
Net current deferred tax assets	112	1,857
Noncurrent:		
Deferred tax assets		
Net operating loss carryforwards (subject to 20 year expiration)	—	1,577
Stock based compensation	346	930
Alternative minimum tax credit carryforward	191	—
Other	20	—
Total noncurrent deferred tax assets	557	2,507
Deferred tax liabilities		
Oil and natural gas properties and equipment	92,321	64,636
Other	—	566
Total noncurrent deferred tax liabilities	92,321	65,202
Net noncurrent deferred tax liabilities	91,764	62,695
Net deferred tax liabilities	$ 91,652	$ 60,838

As of December 31, 2013, the Company had a federal net operating loss carryforward of $5,833. However, a related deferred tax asset is not reflected as the excess tax benefit has not been recognized for certain stock-based compensation deductions which have not reduced current taxes payable. As of December 31, 2013, the Company also had recognized a $191 deferred tax asset related to alternative minimum tax credits which have no expiration date and will be available or use against tax on future taxable income.

12. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the combined consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company's fixed price swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on New York Mercantile Exchange West Texas Intermediate pricing, Argus Louisiana light sweet pricing or Inter–Continental Exchange ("ICE") pricing for Brent crude oil. The counterparty to the Company's derivative contracts is Wells Fargo Bank, N.A., who the Company believes is an acceptable credit risk.

(Amounts in thousands, except per share, per BOE and acreage amounts)

As of December 31, 2013, the Company had open crude oil derivative positions with respect to future production as set forth in the tables below. When aggregating multiple contracts, the weighted average contract price is disclosed.

Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
January - December 2014	944,000	$ 98.78
January 2015	31,000	101.00

Crude Oil—ICE Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
January - April 2014	120,000	$ 109.70

Balance sheet offsetting of derivative assets and liabilities

The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of December 31, 2013 and December 31, 2012.

	December 31, 2013		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Derivative assets	$ 998	$ (567)	$ 431

	December 31, 2012		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Derivative liabilities	$ 5,205	$ —	$ 5,205

The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	December 31, 2013	December 31, 2012
Current Assets: Derivative instruments	$ 213	$ —
Noncurrent Assets: Derivative instruments	218	—
Total Assets	$ 431	$ —
Current Liabilities: Derivative instruments	$ —	$ 4,817
Noncurrent Liabilities: Derivative instruments	—	388
Total Liabilities	$ —	$ 5,205

(Amounts in thousands, except per share, per BOE and acreage amounts)

None of the Company's derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the gains and losses on derivative instruments included in the combined consolidated statements of operations:

	Year Ended December 31,		
	2013	2012	2011
Non-cash gain (loss) on open non-hedge derivative instruments	$ 5,346	$ 8,057	$ (12,972)
Loss on settlement of non-hedge derivative instruments	(7,218)	(5,440)	(37)
Gain (loss) on derivative instruments	$ (1,872)	$ 2,617	$ (13,009)

13. FAIR VALUE MEASUREMENTS

Fair value is defined as 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. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. The fair values of the Company's fixed price crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2013 and December 31, 2012.

	Fair value measurements at December 31, 2013 using:			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	$ —	$ 431	$ —	$ 431

(Amounts in thousands, except per share, per BOE and acreage amounts)

	Fair value measurements at December 31, 2012 using:			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Liabilities:				
Fixed price swaps	$ —	$ 5,205	$ —	$ 5,205

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the combined consolidated financial statements.

	December 31, 2013		December 31, 2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Debt:				
Revolving credit facility	$ 10,000	$ 10,000	$ —	$ —
7.625% Senior Notes due 2021	450,000	460,406	—	—
Note payable	—	—	338	305

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the December 31, 2013 quoted market price, a Level 1 classification in the fair value hierarchy. The fair value of the note payable is determined using internal discounted cash flow calculations based on the interest rate and payment terms of the note payable. The fair value of the note payable is classified as Level 3 in the fair value hierarchy.

14. COMMITMENTS AND CONTINGENCIES

In September 2010, Windsor Permian (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota, that was prospective for hydraulic fracturing grade sand. Prior to the purchase, the prior owners of the property had entered into a Mineral Development Agreement with the plaintiff and the Company purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by the plaintiff against the prior owners of the property, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, the plaintiff seeks damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff’s contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference, and the parties have agreed upon a schedule for pretrial activities. Subsequently, the plaintiff disclosed a new damage theory, and the defendants filed motions with the court to dismiss plaintiff’s claims on the grounds that the damage claim is speculative and that plaintiff cannot prove damages as a matter of law. Plaintiff also filed a motion for leave to amend its complaint to assert a punitive damage claim. The motions were argued in December 2013 and the Company currently anticipate a ruling before the end of March 2014. The Company believes these claims are without merit and will continue to vigorously defend this action. While management has determined that the possibility of loss is remote, litigation is inherently uncertain and management cannot determine the amount of loss, if any, that may result.

(Amounts in thousands, except per share, per BOE and acreage amounts)

The Company could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

Lease Commitments

The following is a schedule of minimum future lease payments with commitments that have initial or remaining noncancelable lease terms in excess of one year as of December 31, 2013.

Year Ending December 31,	Office and Equipment Leases
2014	$ 667
2015	682
2016	505
2017	301
2018	25
Thereafter	—
Total	$ 2,180

The Company leases office space in Midland, Texas from a third party and leases office space in Midland, Texas and Oklahoma City, Oklahoma from related parties. Refer to Note 10—Related Party Transactions for further information on the related party lease agreements. In March 2011, the Company began leasing field office space in Midland, Texas from a third party. The lease term is 84 months with equal monthly installments that escalate 3% annually on March 1st of each year. The following table presents rent expense for the years ended December 31, 2013, 2012 and 2011.

	For the years ended December 31,		
	2013	2012	2011
Rent Expense	$ 571	$ 547	$ 74

Drilling contracts

As of December 31, 2013, the Company had entered into drilling rig contracts with one related party and various third parties in the ordinary course of business to ensure rig availability to complete the Company’s drilling projects. Refer to Note 10—Related Party Transactions for further information on the related party drilling agreement. These commitments are not recorded in the accompanying consolidated balance sheets. Future commitments as of December 31, 2013 total approximately $4,729.

Oil production purchase agreement

On May 24, 2012, the Company entered into an oil purchase agreement with Shell Trading, in which the Company is obligated to commence delivery of specified quantities of oil to Shell Trading upon completion of the reversal of the Magellan Longhorn pipeline and its conversion for oil shipment, which occurred on October 1, 2013. The Company’s agreement with Shell Trading has an initial term of 5 years from the completion date. The Company’s maximum delivery obligation under this agreement is 8 gross barrels per day. The Company has a one-time right to elect to decrease the contract quantity by not more than 20% of the then-current quantity, which decreased contract quantity will be effective for the remainder of the term of the agreement. The Company will receive the price per barrel of oil based on the arithmetic average of the daily settlement price for “Light Sweet Crude Oil” Prompt Month future contracts reported by the New York Mercantile Exchange over the one-month period, as adjusted based on adjustment formulas specified in the agreement. If the Company fails to deliver the required quantities of oil under the agreement during any three-month period following the service commencement date, the Company has agreed to pay Shell Trading a deficiency payment, which is calculated by multiplying (i) the volume of oil that the Company failed to deliver as required under the agreement during such period by (ii) Magellan's Longhorn Spot tariff rate in effect for transportation from Crane, Texas to the Houston Ship Channel for the period of time for which such deficiency volume is calculated. The agreement may be terminated by Shell Trading in the event that Shell Trading's contract for transportation on the pipeline is terminated.

(Amounts in thousands, except per share, per BOE and acreage amounts)

Fracturing and well stimulation agreement

The Company has a contractual obligation with a third-party service provider for fracturing and well stimulation services. The agreement has a term through March 31, 2014. As of December 31, 2013, the future minimum commitment was approximately $3,600.

Defined contribution plan

The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees at their date of hire. The plan allows eligible employees to contribute up to 100% of their annual compensation, not to exceed annual limits established by the federal government. The Company makes matching contributions of up to 6% of an employee's compensation and may make additional discretionary contributions for eligible employees. Employer contributions vest in equal annual installments over a 4 year period. For the year ended December 31, 2013 and 2012 the Company paid $262 and $86, respectively, in contributions to the plan. Prior to 2012, the previous plan was sponsored under the shared service agreements discussed in Note 10—Related Party Transactions and the Company did not directly contribute to the previous plan.

15. SUBSEQUENT EVENTS

On January 2, 2014 the Company granted 79 performance awards with a combination of market and service vesting criteria and 79 restricted stock awards with service vesting criteria under the 2012 Plan. For the performance awards the Company will use an appropriate fair value model to determine the fair value on the date of grant of the performance stock awards, which is expensed over the applicable two year vesting period of these awards. For the restricted stock awards the Company will estimate the fair values of restricted stock awards as the closing price of the Company's common stock on the grant date of the award, which is expensed over the applicable two year vesting period of these awards.

On January 28, 2014, the Company entered into a new commodity contract with JP Morgan Chase Bank, National Association. The derivative is a fixed price oil swap that will settle against the weighted average price per barrel of Argus Louisiana light sweet during the calculation period. The following table presents the terms of the contract:

	Volumes (Bbls)	Fixed Swap Price	Production Period
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	365,000	$ 96.75	February 2014 - January 2015

On February 19, 2014, the Company entered into a new commodity contract with Wells Fargo Bank, N. A. The derivative is a fixed price oil swap that will settle against the calendar month average price per barrel of Argus Louisiana light sweet during the calculation period. The following table presents the terms of the contract:

	Volumes (Bbls)	Fixed Swap Price	Production Period
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	365,000	$ 100.60	March 2014 - February 2015

(Amounts in thousands, except per share, per BOE and acreage amounts)

16. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS OPERATIONS (Unaudited)

The Company’s oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized oil and natural gas costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are as follows:

	December 31,	
	2013	2012
Oil and Natural Gas Properties:		
Proved properties	$ 1,278,799	$ 576,497
Unproved properties	369,561	121,245
Total Oil and Natural Gas Properties	1,648,360	697,742
Less Accumulated depreciation, depletion, amortization and impairment	(210,837)	(145,102)
Net oil and natural gas properties capitalized	$ 1,437,523	$ 552,640

Costs incurred in oil and natural gas activities

Costs incurred in oil and natural gas property acquisition, exploration and development activities are as follows:

	Year Ended December 31,		
	2013	2012	2011
Acquisition costs			
Proved properties	$ 339,130	$ 115,760	$ —
Unproved properties	279,402	117,395	3,704
Development costs	88,460	106,261	75,374
Exploration costs	242,929	17,547	11,226
Capitalized asset retirement costs	697	948	297
Total	$ 950,618	$ 357,911	$ 90,601

(Amounts in thousands, except per share, per BOE and acreage amounts)

Results of Operations from Oil and Natural Gas Producing Activities

The following schedule sets forth the revenues and expenses related to the production and sale of oil and natural gas. It does not include any interest costs or general and administrative costs and, therefore, is not necessarily indicative of the contribution to consolidated net operating results of our oil, natural gas and natural gas liquids operations.

	Year Ended December 31,		
	2013	**2012**	**2011**
Oil, natural gas and natural gas liquid sales	$ 208,002	$ 74,962	$ 47,875
Lease operating expenses	(21,157)	(15,247)	(9,931)
Production and ad valorem taxes	(12,899)	(5,237)	(3,032)
Gathering and transportation	(918)	(424)	(202)
Depreciation, depletion, and amortization	(65,821)	(25,772)	(15,377)
Asset retirement obligation accretion expense	(201)	(98)	(65)
Income tax expense	(31,754)	(54,903)	—
Results of operations	$ 75,252	$ (26,719)	$ 19,268
Pro forma information			
Pro forma results of operations before income taxes		$ 28,184	
Pro forma income tax[(1)]		(10,083)	
Pro forma results of operations		$ 18,101	

(1) Diamondback Energy, Inc. was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback Energy, Inc. is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and the Predecessors were subject to income taxes since December 31, 2011. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

Oil and Natural Gas Reserves

Proved oil and natural gas reserve estimates as of December 31, 2013, 2012 and 2011 were prepared by Ryder Scott Company, L.P., independent petroleum engineers. Proved reserves were estimated in accordance with guidelines established by the SEC, which require that reserve estimates be prepared under existing economic and operating conditions based upon the 12-month unweighted average of the first-day-of-the-month prices.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

(Amounts in thousands, except per share, per BOE and acreage amounts)

The changes in estimated proved reserves are as follows:

	Oil (Bbls)	Natural Gas Liquids (Bbls)	Natural Gas (Mcf)
Proved Developed and Undeveloped Reserves:			
As of January 1, 2011	19,630,160	5,832,967	22,695,080
Extensions and discoveries	1,799,175	466,538	1,884,192
Revisions of previous estimates	(2,879,429)	(1,163,130)	(3,614,167)
Purchase of reserves in place	—	—	—
Production	(449,433)	(86,815)	(413,640)
As of December 31, 2011	18,100,473	5,049,560	20,551,465
Extensions and discoveries	3,106,433	869,741	3,759,684
Revisions of previous estimates	(1,464,243)	(5,811)	383,335
Purchase of reserves in place	7,210,482	2,521,053	10,709,180
Production	(756,286)	(183,114)	(833,516)
As of December 31, 2012	26,196,859	8,251,429	34,570,148
Extensions and discoveries	17,041,744	4,597,856	24,184,540
Revisions of previous estimates	(5,943,164)	(3,455,306)	(5,786,180)
Purchase of reserves in place	7,328,162	1,672,824	10,441,485
Production	(2,022,749)	(361,079)	(1,730,497)
As of December 31, 2013	42,600,852	10,705,724	61,679,496
Proved Developed Reserves:			
January 1, 2011	3,371,460	1,126,431	4,336,720
December 31, 2011	3,949,099	1,263,711	5,285,945
December 31, 2012	7,189,367	2,999,440	12,864,941
December 31, 2013	19,789,965	4,973,493	31,428,756
Proved Undeveloped Reserves:			
January 1, 2011	16,258,700	4,706,536	18,358,360
December 31, 2011	14,151,375	3,785,850	15,265,520
December 31, 2012	19,007,492	5,251,989	21,705,207
December 31, 2013	22,810,887	5,732,231	30,250,740

Revisions represent changes in previous reserves estimates, either upward or downward, resulting from new information normally obtained from development drilling and production history or resulting from a change in economic factors, such as commodity prices, operating costs or development costs.

The Company experienced downward reserve revisions in estimated proved oil, natural gas and natural gas liquid reserves in 2013. The downward revisions were primarily a result of downgrading 92 vertical locations that were booked as PUDs to probable in accordance with the SEC five year PUD rule.

The Company experienced downward reserve revisions in estimated proved oil and natural gas liquid reserves in 2012. These downward revisions were primarily a result from lower product pricing in 2012 as compared to 2011 causing wells to reach their economic limit sooner. The upward revision in natural gas reserves is the result of higher producing natural gas to oil ratios than previously projected, which more than offset the reduction resulting from lower natural gas prices.

The Company experienced downward reserve revisions in estimated proved reserves in 2011. These downward revisions were primarily the result of negative revisions in proved undeveloped wells due to offset well performance; exclusion of proved undeveloped locations that were not scheduled to be drilled within the next five years; and the movement of reserves previously categorized as proved undeveloped to probable reserves due to changes in booking methodology used by our independent petroleum engineers as well as performance of wells in one prospect area.

(Amounts in thousands, except per share, per BOE and acreage amounts)

Standardized Measure of Discounted Future Net Cash Flows

The following information has been prepared in accordance with the provisions of the FASB Codification, Topic 932– "Extractive Activities—Oil and Gas." The standardized measure of discounted future net cash flows are based on the unweighted average, first-day-of-the-month price. The projections should not be viewed as realistic estimates of future cash flows, nor should the "standardized measure" be interpreted as representing current value to the Company. Material revisions to estimates of proved reserves may occur in the future; development and production of the reserves may not occur in the periods assumed; actual prices realized are expected to vary significantly from those used; and actual costs may vary.

The following table sets forth the standardized measure of discounted future net cash flows attributable to the Company's proved oil and natural gas reserves as of December 31, 2013, 2012 and 2011.

	December 31,		
	2013	**2012**	**2011**
Future cash inflows	$ 4,604,241	$ 2,769,485	$ 2,049,520
Future development costs	(517,075)	(541,445)	(410,350)
Future production costs	(806,895)	(773,611)	(497,808)
Future production taxes	(318,396)	(140,758)	(104,856)
Future income tax expenses	(674,260)	(334,903)	—
Future net cash flows	2,287,615	978,768	1,036,506
10% discount to reflect timing of cash flows	(1,311,976)	(611,548)	(671,894)
Standardized measure of discounted future net cash flows	$ 975,639	$ 367,220	$ 364,612

In the table below the average first-day-of–the-month price for oil, natural gas and natural gas liquids is presented, all utilized in the computation of future cash inflows.

	December 31,		
	2013	**2012**	**2011**
	Unweighted Arithmetic Average First-Day-of-the-Month Prices		
Oil (per Bbl)	$ 92.59	$ 88.13	$ 93.09
Natural gas (per Mcf)	$ 4.13	$ 2.86	$ 3.91
Natural gas liquids (per Bbl)	$ 37.82	$ 43.88	$ 56.33

(Amounts in thousands, except per share, per BOE and acreage amounts)

Principal changes in the standardized measure of discounted future net cash flows attributable to the Company's proved reserves are as follows:

	Year Ended December 31,		
	2013	**2012**	**2011**
Standardized measure of discounted future net cash flows at the beginning of the period	$ 367,220	$ 364,612	$ 339,001
Sales of oil and natural gas, net of production costs	(173,946)	(54,208)	(34,711)
Purchase of minerals in place	305,109	107,897	—
Extensions and discoveries, net of future development costs	552,450	79,293	73,571
Previously estimated development costs incurred during the period	76,631	88,849	87,530
Net changes in prices and production costs	51,828	(76,515)	82,364
Changes in estimated future development costs	(5,822)	8,309	(82,855)
Revisions of previous quantity estimates	(126,993)	(22,882)	(98,533)
Accretion of discount	57,988	36,461	33,900
Net change in income taxes	(168,570)	(125,542)	—
Net changes in timing of production and other	39,744	(39,054)	(35,655)
Standardized measure of discounted future net cash flows at the end of the period	$ 975,639	$ 367,220	$ 364,612

(Amounts in thousands, except per share, per BOE and acreage amounts)

17. QUARTERLY FINANCIAL DATA (Unaudited)

The Company's unaudited quarterly financial data for 2013 and 2012 is summarized below.

	2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 28,909	$ 45,394	$ 57,791	$ 75,908
Income from operations	8,662	19,383	29,423	37,726
Income tax expense	3,162	7,802	9,099	11,691
Net income (loss)	$ 5,396	$ 14,471	$ 14,596	$ 20,124
Earnings per common share				
Basic	$ 0.15	$ 0.37	$ 0.33	$ 0.43
Diluted	$ 0.15	$ 0.36	$ 0.33	$ 0.42

	2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$ 16,351	$ 16,030	$ 16,814	$ 25,767
Income from operations	6,737	4,307	4,086	2,177
Income tax expense	—	—	—	54,903
Net income (loss)	$ 1,477	$ 13,624	$ 452	$ (52,074)
Pro forma information				
Income before income taxes	$ 1,477	$ 13,624	$ 452	$ 2,829
Pro forma provision for income taxes	526	4,857	161	1,009
Pro forma net income	$ 951	$ 8,767	$ 291	$ 1,820
Pro forma earnings per share:				
Basic	$ 0.06	$ 0.60	$ 0.02	$ 0.05
Diluted	$ 0.06	$ 0.60	$ 0.02	$ 0.05

Pro Forma Income Taxes

Diamondback Energy, Inc. was formed as a holding company on December 30, 2011, and did not conduct any material business operations prior to the Merger. Diamondback Energy, Inc. is a C-Corp under the Internal Revenue Code and is subject to income taxes. The Company computed a pro forma income tax provision as if the Company and the Predecessors were subject to income taxes since December 31, 2011. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

Pro Forma Earnings per Share

The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued upon the Merger were outstanding for the entire year. Diluted earnings per share reflects the potential dilution, using the treasury stock method, which assumes that options were exercised and restricted stock awards and units were fully vested. During periods in which the Company realizes a net loss, options and restricted stock awards would not be dilutive to net loss per share and conversion into common stock is assumed not to occur.

18. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P and Diamondback O&G are unconditional guarantor's (the "Guarantor Subsidiaries") of the Senior Notes and the second amended and restated credit agreement. On June 23, 2014, in connection with the initial public offering of Viper Energy Partners LP ("Viper") the Company designated Viper, its general partner, Viper Energy Partners GP, and Viper's subsidiary Viper Energy Partners LLC as unrestricted subsidiaries under the Indenture and upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed consolidated financial information as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 on an issuer (parent company), Guarantor Subsidiaries, Non–Guarantor Subsidiaries and consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Balance Sheet
December 31, 2013

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 526	$ 14,267	$ 762	$ —	$ 15,555
Accounts receivable	—	28,544	—	9,426	37,970
Accounts receivable - related party	—	1,303	—	—	1,303
Royalty income receivable	—	—	9,426	(9,426)	—
Intercompany receivable	715,169	413,744	—	(1,128,913)	—
Intercompany note receivable	440,000	—	—	(440,000)	—
Inventories	—	5,631	—	—	5,631
Deferred income taxes	112	—	—	—	112
Other current assets	—	1,397	—	—	1,397
Total current assets	1,155,807	464,886	10,188	(1,568,913)	61,968
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	1,200,326	448,034	—	1,648,360
Pipeline and gas gathering assets	—	6,142	—	—	6,142
Other property and equipment	—	4,071	—	—	4,071
Accumulated depletion, depreciation, amortization and impairment	—	(207,037)	(5,199)	—	(212,236)
	—	1,003,502	442,835	—	1,446,337
Investment in subsidiaries	235,334	—	—	(235,334)	—
Other assets	10,207	3,102	—	—	13,309
Total assets	$ 1,401,348	$ 1,471,490	$ 453,023	$ (1,804,247)	$ 1,521,614
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 2,679	$ —	$ —	$ 2,679
Accounts payable-related party	—	17	—	—	17
Intercompany payable	3,920	1,115,214	87	(1,119,221)	—
Intercompany accrued interest	—	—	9,692	(9,692)	—
Other current liabilities	10,123	108,245	256	—	118,624
Total current liabilities	14,043	1,226,155	10,035	(1,128,913)	121,320
Long-term debt	450,000	10,000	—	—	460,000
Intercompany note payable	—	—	440,000	(440,000)	—
Asset retirement obligations	—	2,989	—	—	2,989
Deferred income taxes	91,764	—	—	—	91,764
Total liabilities	555,807	1,239,144	450,035	(1,568,913)	676,073
Commitments and contingencies					
Stockholders' equity:	845,541	232,346	2,988	(235,334)	845,541
Total equity	845,541	232,346	2,988	(235,334)	845,541
Total liabilities and equity	$ 1,401,348	$ 1,471,490	$ 453,023	$ (1,804,247)	$ 1,521,614

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Balance Sheet
December 31, 2012

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 14	$ 26,344	$ —	$ —	$ 26,358
Accounts receivable	—	14,040	—	—	14,040
Accounts receivable - related party	—	772	—	—	772
Intercompany receivable	381,495	24,940	—	(406,435)	—
Inventories	—	6,195	—	—	6,195
Deferred income taxes	1,857	—	—	—	1,857
Other current assets	39	1,014	—	—	1,053
Total current assets	383,405	73,305	—	(406,435)	50,275
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	697,742	—	—	697,742
Other property and equipment	—	2,337	—	—	2,337
Accumulated depletion, depreciation, amortization and impairment	—	(145,837)	—	—	(145,837)
	—	554,242	—	—	554,242
Investment in subsidiaries	144,461	—	—	(144,461)	—
Other assets	—	2,184	—	—	2,184
Total assets	$ 527,866	$ 629,731	$ —	$ (550,896)	$ 606,701
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$ 9	$ 12,132	$ —	$ —	$ 12,141
Accounts payable-related party	—	18,813	—	—	18,813
Intercompany payable	3,020	403,415	—	(406,435)	—
Other current liabilities	74	48,204	—	—	48,278
Total current liabilities	3,103	482,564	—	(406,435)	79,232
Long-term debt	—	193	—	—	193
Asset retirement obligations	—	2,125	—	—	2,125
Other liabilities	—	388	—	—	388
Deferred income taxes	62,695	—	—	—	62,695
Total liabilities	65,798	485,270	—	(406,435)	144,633
Commitments and contingencies					
Stockholders’ equity:	462,068	144,461	—	(144,461)	462,068
Total equity	462,068	144,461	—	(144,461)	462,068
Total liabilities and equity	$ 527,866	$ 629,731	$ —	$ (550,896)	$ 606,701

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2013

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 174,868	$ —	$ 13,885	$ 188,753
Natural gas sales	—	5,852	—	397	6,249
Natural gas liquid sales	—	12,295	—	705	13,000
Royalty income	—	—	14,987	(14,987)	—
Total revenues	—	193,015	14,987	—	208,002
Costs and expenses:					
Lease operating expenses	—	21,157	—	—	21,157
Production and ad valorem taxes	—	11,927	972	—	12,899
Gathering and transportation	—	918	—	—	918
Depreciation, depletion and amortization	—	61,398	5,199	—	66,597
General and administrative expenses	3,909	7,127	—	—	11,036
Asset retirement obligation accretion expense	—	201	—	—	201
Intercompany charges	—	—	87	(87)	—
Total costs and expenses	3,909	102,728	6,258	(87)	112,808
Income (loss) from operations	(3,909)	90,287	8,729	87	95,194
Other income (expense)					
Interest income	1	—	—	—	1
Interest income - intercompany	5,741	—	—	(5,741)	—
Interest expense	(592)	(7,467)	—	—	(8,059)
Interest expense - intercompany	—	—	(5,741)	5,741	—
Other income - related party	—	1,077	—	—	1,077
Other income - intercompany	—	87	—	(87)	—
Other expense	—	—	—	—	—
Loss on derivative instruments, net	—	(1,872)	—	—	(1,872)
Total other income (expense), net	5,150	(8,175)	(5,741)	(87)	(8,853)
Income before income taxes	1,241	82,112	2,988	—	86,341
Provision for income taxes	31,754	—	—	—	31,754
Net income (loss)	$ (30,513)	$ 82,112	$ 2,988	$ —	$ 54,587

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2012

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 65,704	$ —	$ —	$ 65,704
Natural gas sales	—	2,379	—	—	2,379
Natural gas liquid sales	—	6,879	—	—	6,879
Total revenues	—	74,962	—	—	74,962
Costs and expenses:					
Lease operating expenses	—	15,247	—	—	15,247
Production and ad valorem taxes	—	5,237	—	—	5,237
Gathering and transportation	—	424	—	—	424
Depreciation, depletion and amortization	—	26,273	—	—	26,273
General and administrative expenses	2,665	7,711	—	—	10,376
Asset retirement obligation accretion expense	—	98	—	—	98
Intercompany charges	—	84	—	(84)	—
Total costs and expenses	2,665	55,074	—	(84)	57,655
Income (loss) from operations	(2,665)	19,888	—	84	17,307
Other income (expense)					
Interest income	—	3	—	—	3
Interest expense	—	(3,610)	—	—	(3,610)
Other income - related party	—	2,132	—	—	2,132
Other income - intercompany	—	84	—	(84)	—
Gain on derivative instruments, net	—	2,617	—	—	2,617
Loss from equity investment	—	(67)	—	—	(67)
Total other income (expense), net	—	1,159	—	(84)	1,075
Income (loss) before income taxes	(2,665)	21,047	—	—	18,382
Provision for income taxes	54,903	—	—	—	54,903
Net income (loss)	$ (57,568)	$ 21,047	$ —	$ —	$ (36,521)

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Statement of Operations
Year Ended December 31, 2011

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 2,582	$ —	$ —	$ 2,582
Oil sales - related party	—	38,873	—	—	38,873
Natural gas sales	—	1,647	—	—	1,647
Natural gas liquid sales	—	4,773	—	—	4,773
Oil and natural gas services - related party	—	1,491	—	—	1,491
Total revenues	—	49,366	—	—	49,366
Costs and expenses:					
Lease operating expenses	—	10,597	—	—	10,597
Production and ad valorem taxes	—	2,366	—	—	2,366
Gathering and transportation	—	202	—	—	202
Oil and natural gas services	—	1,733	—	—	1,733
Depreciation, depletion and amortization	—	15,601	—	—	15,601
General and administrative expenses	—	3,655	—	—	3,655
Asset retirement obligation accretion expense	—	65	—	—	65
Intercompany charges	—	—	—	—	—
Total costs and expenses	—	34,219	—	—	34,219
Income from operations	—	15,147	—	—	15,147
Other income (expense)					
Interest income	—	11	—	—	11
Interest expense	—	(2,528)	—	—	(2,528)
Loss on derivative instruments, net	—	(13,009)	—	—	(13,009)
Loss from equity investment	—	(7)	—	—	(7)
Total other expense, net	—	(15,533)	—	—	(15,533)
Net Loss	$ —	$ (386)	$ —	$ —	$ (386)

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2013

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 12,302	$ 138,630	$ 4,845	$ —	$ 155,777
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(288,503)	(4,083)	—	(292,586)
Acquisition of leasehold interests	—	(639,976)	—	—	(639,976)
Intercompany transfers	(729,344)	729,344	—	—	—
Other investing activities	—	(7,578)	—	—	(7,578)
Net cash used in investing activities	(729,344)	(206,713)	(4,083)	—	(940,140)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	59,000	—	—	59,000
Repayment on credit facility	—	(49,000)	—	—	(49,000)
Proceeds from senior notes	450,000	—	—	—	450,000
Proceeds from public offerings	322,680	—	—	—	322,680
Distribution to parent	—	—	—	—	—
Intercompany transfers	(49,000)	49,000	—	—	—
Other financing activities	(6,126)	(2,994)	—	—	(9,120)
Net cash provided by financing activities	717,554	56,006	—	—	773,560
Net increase (decrease) in cash and cash equivalents	512	(12,077)	762	—	(10,803)
Cash and cash equivalents at beginning of period	14	26,344	—	—	26,358
Cash and cash equivalents at end of period	$ 526	$ 14,267	$ 762	$ —	$ 15,555

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2012

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 861	$ 48,831	$ —	$ —	$ 49,692
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(111,797)	—	—	(111,797)
Acquisition of leasehold interests	—	(63,590)	—	—	(63,590)
Intercompany transfers	(107,961)	107,961	—	—	—
Other investing activities	—	(7,691)	—	—	(7,691)
Net cash used in investing activities	(107,961)	(75,117)	—	—	(183,078)
Proceeds from borrowing on credit facility	—	15,000	—	—	15,000
Repayment on credit facility	—	(100,000)	—	—	(100,000)
Proceeds from public offerings	237,164	—	—	—	237,164
Intercompany transfers	(130,050)	130,050	—	—	—
Other financing activities	—	(3,337)	—	—	(3,337)
Net cash provided by financing activities	107,114	45,671	—	—	152,785
Net increase in cash and cash equivalents	14	19,385	—	—	19,399
Cash and cash equivalents at beginning of period	—	6,959	—	—	6,959
Cash and cash equivalents at end of period	$ 14	$ 26,344	$ —	$ —	$ 26,358

(Amounts in thousands, except per share, per BOE and acreage amounts)

Condensed Consolidated Statement of Cash Flows
Year Ended December 31, 2011

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ —	$ 30,998	$ —	$ —	$ 30,998
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(80,174)	—	—	(80,174)
Deconsolidation of Bison	—	(10)	—	—	(10)
Proceeds from sale of membership interest in equity investment	—	6,010	—	—	6,010
Other investing activities	—	(6,934)	—	—	(6,934)
Net cash used in investing activities	—	(81,108)	—	—	(81,108)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	40,233	—	—	40,233
Contributions by members	—	13,517	—	—	13,517
Other financing activities	—	(800)	—	—	(800)
Net cash provided by financing activities	—	52,950	—	—	52,950
Net increase in cash and cash equivalents	—	2,840	—	—	2,840
Cash and cash equivalents at beginning of period	—	4,119	—	—	4,119
Cash and cash equivalents at end of period	$ —	$ 6,959	$ —	$ —	$ 6,959

Exhibit 99.4

TABLE OF CONTENTS

(Unaudited)

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

	March 31, 2014	December 31, 2013
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 25,314	$ 15,555
Accounts receivable:		
Joint interest and other	15,920	14,437
Oil and natural gas sales	38,360	23,533
Related party	2,298	1,303
Inventories	5,889	5,631
Deferred income taxes	1,377	112
Derivative instruments	—	213
Prepaid expenses and other	1,495	1,184
Total current assets	90,653	61,968
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($485,184 and $369,561 excluded from amortization at March 31, 2014 and December 31, 2013, respectively)	2,065,571	1,648,360
Pipeline and gas gathering assets	6,503	6,142
Other property and equipment	4,635	4,071
Accumulated depletion, depreciation, amortization and impairment	(243,131)	(212,236)
	1,833,578	1,446,337
Derivative instruments	—	218
Other assets	12,666	13,091
Total assets	$ 1,936,897	$ 1,521,614
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$ 24,487	$ 2,679
Accounts payable-related party	313	17
Accrued capital expenditures	68,207	74,649
Other accrued liabilities	46,649	34,750
Revenues and royalties payable	12,645	9,225
Derivative instruments	2,910	—
Total current liabilities	155,211	121,320
Long-term debt	587,000	460,000
Asset retirement obligations	5,147	2,989
Deferred income taxes	106,630	91,764
Total liabilities	853,988	676,073
Contingencies (Note 12)		
Stockholders' equity:		
Common stock, $0.01 par value, 100,000,000 shares authorized, 50,700,099 issued and outstanding at March 31, 2014; 47,106,216 issued and outstanding at December 31, 2013	508	471
Additional paid-in capital	1,056,299	842,557
Retained earnings	26,102	2,513
Total stockholders' equity	1,082,909	845,541
Total liabilities and stockholders' equity	$ 1,936,897	$ 1,521,614

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
	(In thousands, except per share amounts)	
Revenues:		
Oil sales	$ 89,758	$ 25,253
Natural gas sales	1,755	739
Natural gas sales - related party	1,580	412
Natural gas liquid sales	2,584	1,822
Natural gas liquid sales - related party	2,327	683
Total revenues	98,004	28,909
Costs and expenses:		
Lease operating expenses	7,807	4,706
Lease operating expenses - related party	108	202
Production and ad valorem taxes	5,578	1,878
Production and ad valorem taxes - related party	264	76
Gathering and transportation	214	75
Gathering and transportation - related party	368	58
Depreciation, depletion and amortization	30,973	10,738
General and administrative expenses (including non-cash stock based compensation, net of capitalized amounts, of $2,190 and $458 for the three months ended March 31, 2014 and 2013, respectively)	4,265	2,185
General and administrative expenses - related party	292	286
Asset retirement obligation accretion expense	72	43
Total costs and expenses	49,941	20,247
Income from operations	48,063	8,662
Other income (expense)		
Interest expense	(6,505)	(485)
Other income - related party	30	389
Loss on derivative instruments, net	(4,398)	(8)
Total other income (expense), net	(10,873)	(104)
Income before income taxes	37,190	8,558
Provision for income taxes		
Deferred	13,601	3,162
Net income	$ 23,589	$ 5,396
Earnings per common share		
Basic	$ 0.49	$ 0.15
Diluted	$ 0.48	$ 0.15
Weighted average common shares outstanding		
Basic	48,447	37,059
Diluted	48,867	37,206

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity
(Unaudited)

	Common Stock		Additional	Retained	
	Shares	Amount	Paid-in Capital	Earnings	Total
			(In thousands)		
Balance December 31, 2013	47,106	$ 471	$ 842,557	$ 2,513	$ 845,541
Stock based compensation	—	—	3,256	—	3,256
Common shares issued in public offering, net of offering costs	3,450	35	208,410	—	208,445
Exercise of stock options and vesting of restricted stock units	145	2	2,076	—	2,078
Net income	—	—	—	23,589	23,589
Balance March 31, 2014	50,701	$ 508	$ 1,056,299	$ 26,102	$ 1,082,909

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 23,589	$ 5,396
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	13,601	3,162
Asset retirement obligation accretion expense	72	43
Depreciation, depletion, and amortization	30,973	10,738
Amortization of debt issuance costs	458	153
Change in fair value of derivative instruments	3,342	(1,537)
Stock based compensation expense	2,190	655
Gain on sale of assets	(11)	(9)
Changes in operating assets and liabilities:		
Accounts receivable	(12,490)	(8,393)
Accounts receivable-related party	(995)	3,908
Inventories	(258)	(89)
Prepaid expenses and other	(311)	(415)
Accounts payable and accrued liabilities	7,590	3,243
Accounts payable and accrued liabilities-related party	296	(108)
Revenues and royalties payable	3,420	108
Net cash provided by operating activities	71,466	16,855
Cash flows from investing activities:		
Additions to oil and natural gas properties	(84,211)	(50,094)
Additions to oil and natural gas properties-related party	(1,650)	(4,868)
Acquisition of Gulfport properties	—	(18,550)
Acquisition of leasehold interests	(312,207)	—
Pipeline and gas gathering assets	(532)	—
Purchase of other property and equipment	(595)	(302)
Proceeds from sale of property and equipment	11	9
Settlement of non-hedge derivative instruments	—	(289)
Net cash used in investing activities	(399,184)	(74,094)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	127,000	36,500
Debt issuance costs	(82)	—
Public offering costs	(75)	(103)
Proceeds from public offering	208,644	—
Exercise of stock options	1,990	—
Net cash provided by financing activities	337,477	36,397
Net increase (decrease) in cash and cash equivalents	9,759	(20,842)
Cash and cash equivalents at beginning of period	15,555	26,358
Cash and cash equivalents at end of period	$ 25,314	$ 5,516

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows - Continued
(Unaudited)

	Three Months Ended March 31,	
	2014	2013
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$ 149	$ 141
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$ 214	$ 62
Asset retirement obligation revisions in estimated liability	$ 588	$ —
Asset retirement obligation acquired	$ 1,294	$ —

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements
(Unaudited)

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc. ("Diamondback" or the "Company") together with its subsidiaries, is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Diamondback was incorporated in Delaware on December 30, 2011.

The subsidiaries of Diamondback, as of March 31, 2014, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners LLC, a Delaware limited liability company, Viper Energy Partners LP, a Delaware limited partnership, and Viper Energy Partners GP LLC, a Delaware limited liability company. The subsidiaries are all wholly owned.

On October 11, 2012, Diamondback acquired from Gulfport Energy Corporation ("Gulfport") all of its oil and natural gas interests in the Permian Basin (the "Gulfport properties") in exchange for shares of Diamondback common stock and a promissory note in a transaction referred to as the "Gulfport transaction". The Gulfport transaction was treated as a business combination accounted for under the acquisition method of accounting with the identifiable assets and liabilities recognized at fair value on the date of transfer.

On May 21, 2013, the Company completed an underwritten primary public offering of 5,175,000 shares of common stock, which included 675,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $29.25 per share and the Company received net proceeds of approximately $144.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

On June 24, 2013, Gulfport and certain entities controlled by Wexford Capital, LP ("Wexford"), our equity sponsor, completed an underwritten secondary public offering of 6,000,000 shares of the Company's common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of the Company's common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at $34.75 per share and the selling stockholders received all proceeds from this offering.

In August 2013, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $40.25 per share and the Company received net proceeds of approximately $177.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In September 2013, the Company completed an offering of $450.0 million principal amount of its 7.625% Senior Notes due 2021. See Note 6 below.

In February 2014, the Company completed an underwritten public offering of 3,450,000 shares of common stock, which included 450,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $62.67 per share and the Company received net proceeds of approximately $208.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the "SEC"). They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to such rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10–Q should be read in conjunction with the Company’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2013, which contains a summary of the Company’s significant accounting policies and other disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company’s consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company’s disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company’s estimates. Any effects on the Company’s business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

3. ACQUISITIONS

2014 Activity

On February 27 and 28, 2014, the Company completed acquisitions of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest). The acquisitions were accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. These acquisitions were funded in part by the net proceeds of the February 2014 equity offering discussed in Note 1 above.

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition dates. The aggregate consideration transferred was $292,159,000 in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

		(in thousands)
Proved oil and natural gas properties	$	170,174
Unevaluated oil and natural gas properties		123,243
Asset retirement obligations		(1,258)
Total fair value of net assets	$	292,159

The Company has included in its consolidated statements of operations revenues of $4,898,000 and direct operating expenses of $1,074,000 for the period from February 28, 2014 to March 31, 2014 due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion. The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three months ended March 31, 2014 and 2013 has been prepared to give effect to the acquisitions as if they had occurred on January 1, 2013. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2013. The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

	Three Months Ended March 31, 2014 (Pro Forma)	Three Months Ended March 31, 2013 (Pro Forma)
	(in thousands, except per share amounts)	
Revenues	$ 107,979	$ 44,391
Income from operations	52,193	14,656
Net income	26,209	9,175
Basic earnings per common share	$ 0.54	$ 0.25
Diluted earnings per common share	$ 0.54	$ 0.25

2013 Activity

In September 2013, the Company completed two separate acquisitions of additional leasehold interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $165.0 million, subject to certain adjustments. The first of these acquisitions closed on September 4, 2013 when the Company acquired certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres. The second of these acquisitions closed on September 26, 2013, when the Company acquired certain assets located primarily in southwestern Dawson County, Texas, consisting of a 71% working interest (55% net revenue interest) in 9,390 gross (6,638 net) acres. These acquisitions were funded with a portion of the net proceeds from the August 2013 equity offering discussed in Note 1 above.

On September 19, 2013, the Company completed the acquisition of the mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. The mineral interests entitle the Company to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. The $440.0 million purchase price was funded with the net proceeds of the Company's offering of Senior Notes discussed in Note 6 below.

4. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	March 31, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$ 1,580,387	$ 1,278,799
Not subject to depletion-acquisition costs		
Incurred in 2014	142,064	—
Incurred in 2013	256,998	279,353
Incurred in 2012	85,358	87,252
Incurred in 2011	764	1,598
Incurred in 2010	—	1,358
Total not subject to depletion	485,184	369,561
Gross oil and natural gas properties	2,065,571	1,648,360
Less accumulated depreciation, depletion, amortization and impairment	(241,514)	(210,837)
Oil and natural gas properties, net	1,824,057	1,437,523
Pipeline and gas gathering assets	6,503	6,142
Other property and equipment	4,635	4,071
Less accumulated depreciation	(1,617)	(1,399)
Other property and equipment, net	3,018	2,672
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 1,833,578	$ 1,446,337

The average depletion rate per barrel equivalent unit of production was $25.19 and $24.50 for the three months ended March 31, 2014 and 2013, respectively. Internal costs capitalized to the full cost pool represent management's estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately $2,296,000 and $692,000 for the three months ended March 31, 2014 and 2013, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company's unevaluated costs into the amortization base is expected to be completed within three to five years.

5. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligation liability for the following periods:

	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Asset retirement obligation, beginning of period	$ 3,029	$ 2,145
Additional liability incurred	214	62
Liabilities acquired	1,294	—
Liabilities settled	(10)	—
Accretion expense	72	43
Revisions in estimated liabilities	588	—
Asset retirement obligation, end of period	5,187	2,250
Less current portion	40	20
Asset retirement obligations - long-term	$ 5,147	$ 2,230

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

6. DEBT

Long-term debt consisted of the following as of the dates indicated:

	March 31, 2014	December 31, 2013
	(in thousands)	
Revolving credit facility	$ 137,000	$ 10,000
7.625 % Senior Notes due 2021	450,000	450,000
Total long-term debt	$ 587,000	$ 460,000

Senior Notes

On September 18, 2013, the Company completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021 (the "Senior Notes"). The Senior Notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014 and will mature on October 1, 2021. The Senior Notes are fully and unconditionally guaranteed by the Company's subsidiaries. The net proceeds from the Senior Notes were used to fund the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin.

The Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee (the “Indenture”). The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company’s ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of subsidiaries, agree to payment restrictions affecting the Company’s restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of the Company’s subsidiaries as unrestricted subsidiaries. If the Company experiences certain kinds of changes of control or if it sells certain of its assets, holders of the Senior Notes may have the right to require the Company to repurchase their Senior Notes.

The Company will have the option to redeem the Senior Notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, the Company may redeem all or a part of the Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a “make-whole” premium at the redemption date. Furthermore, before October 1, 2016, the Company may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the Senior Notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the Senior Notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

In connection with the issuance of the Senior Notes, the Company and the subsidiary guarantors entered into a Registration Rights Agreement (the “Registration Rights Agreement”) with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the Senior Notes for a new issue of substantially identical debt securities registered under the Securities Act, which registration statement was filed with the SEC on March 14, 2014. Under the Registration Rights Agreement, the Company also agreed to use its commercially reasonable efforts to cause the exchange offer registration statement to become effective within 360 days after the issue date of the Senior Notes and to consummate the exchange offer 30 days after effectiveness. The Company may be required to file a shelf registration statement to cover resales of the Senior Notes under certain circumstances. If the Company fails to satisfy certain of its obligations under the Registration Rights Agreement, the Company agreed to pay additional interest to the holders of the Senior Notes as specified in the Registration Rights Agreement.

Credit Facility-Wells Fargo Bank

On October 15, 2010, the Company entered into a secured revolving credit agreement with BNP Paribas, or BNP, as the administrative agent, sole book runner and lead arranger. On May 10, 2012, the revolving credit agreement was amended to provide for the resignation of BNP, and the appointment of Wells Fargo Bank, National Association, as administrative agent for the lenders. The credit agreement was amended and restated as of July 24, 2012 and again as of November 1, 2013. The credit agreement, as so amended and restated, provides for a revolving credit facility in the maximum amount of $600 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Company’s oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of March 31, 2014 and December 31, 2013, the borrowing base was set at $225.0 million. In connection with our April 2014 redetermination, the administrative agent has informed the Company that it has approved a borrowing base of $450.0 million based on the Company’s current assets. As of March 31, 2014, the Company had outstanding borrowings of $137.0 million which bore interest at a weighted average rate of 2.16%. As of December 31, 2013, the Company had outstanding borrowings of $10.0 million which bore interest at a weighted average rate of 1.67%.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is based on the prime rate or LIBOR plus margins ranging from 0.50% for prime-based loans and 1.50% for LIBOR loans to 1.50% for prime-based loans and 2.50% for LIBOR loans, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of November 1, 2018. The loan is secured by substantially all of the assets of the Company and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of March 31, 2014, the Company had $450 million of senior unsecured notes outstanding.

As of March 31, 2014 and December 31, 2013, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company's revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

7. EARNINGS PER SHARE

Earnings Per Share

The Company's basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended March 31, 2014		
	Income	Shares	Per Share
	(in thousands)		
Basic:			
Net income attributable to common stock	$ 23,589	48,446,609	$ 0.49
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$ —	420,110	
Diluted:			
Net income attributable to common stock	$ 23,589	48,866,719	$ 0.48

	Three Months Ended March 31, 2013		
	Income (in thousands)	Shares	Per Share
Basic:			
Net income attributable to common stock	$ 5,396	37,059,071	$ 0.15
Effect of Dilutive Securities:			
Dilutive effect of potential common shares issuable	$ —	146,619	
Diluted:			
Net income attributable to common stock	$ 5,396	37,205,690	$ 0.15

8. STOCK BASED COMPENSATION

For the three months ended March 31, 2014 and 2013, the Company incurred $3,256,000 and $655,000, respectively, of stock based compensation, of which the Company capitalized $1,066,000 and $197,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties.

Stock Options

The following table presents the Company's stock option activity under the 2012 Plan for the three months ended March 31, 2014.

	Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	712,955	$ 17.96		
Granted	—	$ —		
Exercised	(114,050)	$ 18.22		
Expired/Forfeited	—	$ —		
Outstanding at March 31, 2014	598,905	$ 17.91	2.41	$ 29,585
Vested and Expected to vest at March 31, 2014	598,905	$ 17.91	2.41	$ 29,585
Exercisable at March 31, 2014	151,655	$ 17.50	1.69	$ 7,554

The aggregate intrinsic value of stock options that were exercised during the three months ended March 31, 2014 was $5,310,000. As of March 31, 2014, the unrecognized compensation cost related to unvested stock options was $1,465,000. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the 2012 Plan during the three months ended March 31, 2014.

	Restricted Stock Units		Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	132,239	$	19.20
Granted	99,150	$	61.59
Vested	(31,383)	$	61.44
Forfeited	—	$	—
Unvested at March 31, 2014	200,006	$	33.56

The aggregate fair value of restricted stock units that vested during the three months ended March 31, 2014 was $2,003,000. As of March 31, 2014, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $5,619,000. Such cost is expected to be recognized over a weighted-average period of 1.7 years.

Performance Based Restricted Stock Units

To provide long-term incentives for the executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a three-year performance period. In February 2014, eligible employees received initial performance restricted stock unit awards totaling 79,150 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2013 to December 31, 2015 and cliff vest at December 31, 2015. There were no performance restricted stock units issued or outstanding during the three months ended March 31, 2013.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period. The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions.

		2014
Grant-date fair value	$	125.63
Risk-free rate		0.30%
Company volatility		39.60%

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the three months ended March 31, 2014.

	Performance Restricted Stock Units		Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	—	$	—
Granted	79,150	$	125.63
Vested	—	$	—
Forfeited	—	$	—
Unvested at March 31, 2014 (1)	79,150	$	125.63

(1) A maximum of 158,300 units could be awarded based upon the Company's final TSR ranking.

As of March 31, 2014, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $9,470,000. Such cost is expected to be recognized over a weighted-average period of 1.8 years.

9. RELATED PARTY TRANSACTIONS

Administrative Services

An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. The initial term of this shared service agreement was two years. Since the expiration of such two-year period on March 1, 2010, the agreement, by its terms has continued on a month-to-month basis. For the three months ended March 31, 2014 and 2013, the Company incurred total costs of $1,000 and $58,000, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. As of March 31, 2014 and December 31, 2013, the Company owed the administrative services affiliate no amounts and $17,000, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provides this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement was two years. The agreement now continues on a month-to-month basis until canceled by either party upon thirty days prior written notice. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the three months ended March 31, 2014 and 2013, the affiliate reimbursed the Company $30,000 and $389,000, respectively, for services under the shared services agreement. As of March 31, 2014 and December 31, 2013, the affiliate owed the Company $13,000 amounts and no amounts, respectively. These amounts are included in accounts receivable-related party in the accompanying consolidated balance sheets.

Drilling Services

Bison Drilling and Field Services LLC ("Bison"), an entity controlled by Wexford, has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company's most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. At March 31, 2014, Bison was providing drilling services to the Company using one of its rigs. This master drilling agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. The Company incurred total costs for services performed by Bison of $1,510,000 and $4,968,000 for the three months ended March 31, 2014 and 2013, respectively. The Company owed Bison $313,000 as of March 31, 2014 and no amounts as of December 31, 2013.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC ("Panther Drilling"), an entity controlled by Wexford, Panther Drilling provides directional drilling and other services. This master service agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from work performed prior to the termination of the master service agreement. In the third quarter 2013, the Company began using Panther Drilling's directional drilling services. The Company incurred $248,000 for services performed by Panther Drilling. The Company owed Panther Drilling no amounts as of March 31, 2014 or December 31, 2013.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC ("Coronado Midstream"), formerly known as MidMar Gas LLC, an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream, all of the gas conforming to certain quality specifications produced from certain of the Company's Permian Basin acreage. Following the expiration of the initial ten year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days' written notice. Under the gas purchase agreement, Coronado Midstream is obligated to pay the Company 87% of the net revenue received by Coronado Midstream for all components of the Company's dedicated gas, including the liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at Coronado Midstream's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron’s Headlee plant. The Company recognized revenues from Coronado Midstream of $3,907,000 and $1,095,000 for the three months ended March 31, 2014 and 2013, respectively. As of March 31, 2014 and December 31, 2013, Coronado Midstream owed the Company $2,285,000 and $1,303,000, respectively, for the Company’s portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie Proppant LLC (“Muskie”), an entity affiliated with Wexford, processes and sells fracing grade sand for oil and natural gas operations. The Company began purchasing sand from Muskie in March 2013. On May 16, 2013, the Company entered into a master services agreement with Muskie, pursuant to which Muskie agreed to sell custom natural sand proppant to the Company based on the Company’s requirements. The Company is not obligated to place any orders with, or accept any offers from, Muskie for sand proppant. The agreement may be terminated at the option of either party on 30 days’ notice. The Company incurred no costs and costs of $234,000 for sand purchased from Muskie for the three months ended March 31, 2014 and 2013, respectively. The Company owed Muskie no amounts as of March 31, 2014 or December 31, 2013.

Midland Leases

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $93,000 and $38,000 for the three months ended March 31, 2014 and 2013, respectively, under this lease. In the second and third quarters of 2013, the Company amended this agreement to increase the size of the leased premises. The monthly rent under the lease increased from $13,000 to $15,000 beginning on August 1, 2013 and increased further to $25,000 beginning on October 1, 2013. The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

The Company leased field office space in Midland, Texas from an unrelated third party from March 1, 2011 to March 1, 2014. Effective March 1, 2014, the building was purchased by an entity controlled by an affiliate of Wexford. The remaining term of the lease as of March 1, 2014 is four years. The Company paid rent of $11,000 to the related party for the three months ended March 31, 2014. The monthly base rent is $11,000 which will increase 3% annually on March 1 of each year during the remainder of the lease term.

Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $64,000 and $53,000 for the three months ended March 31, 2014 and 2013, respectively, under this lease. Effective April 1, 2013, the Company amended this lease to increase the size of the leased premises, at which time the monthly base rent increased to $19,000 for the remainder of the lease term. The Company is also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises.

Advisory Services Agreement & Professional Services from Wexford

The Company entered into an advisory services agreement (the “Advisory Services Agreement”) with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on October 18, 2012, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company’s independent directors for such services as may be provided by Wexford at the Company’s request in connection with future acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company’s day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct. The Company incurred total costs of $125,000 and $125,000 for the three months ended March 31, 2014 and 2013, respectively, under the Advisory

Services Agreement. As of March 31, 2014 and December 31, 2013, the Company owed Wexford no amounts for either period.

10. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the consolidated statements of operations under the caption “Loss on derivative instruments, net.”

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company’s fixed price swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company’s derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Argus Louisiana light sweet pricing or Inter–Continental Exchange (“ICE”) pricing for Brent crude oil. The counterparties to the Company’s derivative contracts are Wells Fargo Bank, N.A., JP Morgan Chase Bank, National Association and The Bank of Nova Scotia who the Company believes are acceptable credit risks.

As of March 31, 2014, the Company had open crude oil derivative positions with respect to future production as set forth in the tables below. When aggregating multiple contracts, the weighted average contract price is disclosed.

Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
April - December 2014	1,620,000	$ 98.67
January - March 2015	211,000	99.54

Crude Oil—ICE Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
April 2014	30,000	$ 109.70

Balance sheet offsetting of derivative assets and liabilities

The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company’s consolidated balance sheets as of March 31, 2014 and December 31, 2013.

	March 31, 2014 (in thousands)		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Derivative liabilities	$ (3,200)	$ 290	$ (2,910)

	December 31, 2013 (in thousands)		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Derivative assets	$ 998	$ (567)	$ 431

The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	March 31, 2014	December 31, 2013
	(in thousands)	
Current Assets: Derivative instruments	$ —	$ 213
Noncurrent Assets: Derivative instruments	—	218
Total Assets	$ —	$ 431
Current Liabilities: Derivative instruments	$ (2,910)	$ —
Noncurrent Liabilities: Derivative instruments	—	—
Total Liabilities	$ (2,910)	$ —

None of the Company's derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the gains and losses on derivative instruments included in the consolidated statements of operations:

	Three Months Ended March 31,	
	2014	2013
	(in thousands)	
Non-cash gain (loss) on open non-hedge derivative instruments	$ (3,342)	$ 1,535
Loss on settlement of non-hedge derivative instruments	(1,056)	(1,543)
Loss on derivative instruments	$ (4,398)	$ (8)

11. FAIR VALUE MEASUREMENTS

Fair value is defined as 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. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. The fair values of the Company's fixed price crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of March 31, 2014 and December 31, 2013.

	Fair value measurements at March 31, 2014 using:			
	(in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Liabilities:				
Fixed price swaps	—	(2,910)	—	(2,910)

	Fair value measurements at December 31, 2013 using:			
	(in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	$ —	$ 431	$ —	$ 431

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated financial statements.

	March 31, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$ 137,000	$ 137,000	$ 10,000	$ 10,000
7.625% Senior Notes due 2021	450,000	484,875	450,000	460,406

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the March 31, 2014 quoted market price, a Level 1 classification in the fair value hierarchy.

12. CONTINGENCIES

In September 2010, Windsor Permian LLC ("Windsor Permian") (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota, that was prospective for hydraulic fracturing grade sand. Prior to the purchase, the prior owners of the property had entered into a Mineral Development Agreement with the plaintiff and the Company purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by the plaintiff against the prior owners of the property, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, the plaintiff sought damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff's contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference. Subsequently, the plaintiff disclosed a new damage theory, and the defendants filed motions with the court to dismiss plaintiff's claims on the grounds that the damage claim was speculative and that plaintiff could not prove damages as a matter of law. Plaintiff also filed a motion for leave to amend its complaint to assert a punitive damage claim. The motions were argued in December 2013. In March 2014, the judge entered an order granting the defendants' motions to exclude testimony and for summary judgment. All parties agreed not to pursue an appeal from the order and waived any entitlement to costs, which effectively concluded this matter.

The Company could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

13. SUBSEQUENT EVENTS

On each of April 9, 2014 and April 11, 2014, the Company entered into new commodity contracts with The Bank of Nova Scotia. The contracts are both fixed price oil swaps that will settle against the weighted average price per barrel of Argus Louisiana light sweet during the calculation period. The following table presents the terms of the contracts:

	Volumes (Bbls)	Fixed Swap Price	Production Period
Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap	365,000	$ 100.00	May 2014 - April 2015

On May 7, 2014, the Company’s wholly-owned subsidiary Viper Energy Partners LP (“Viper”) filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of limited partner interests. At or prior to the closing of this offering, the Company will contribute to Viper all of the equity interests in the Company’s wholly-owned subsidiary Viper Energy Partners, LLC (“Energy Partners”), in exchange for limited partner interests in Viper. Energy Partners’ assets currently consist of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin, approximately 50% of which are operated by us. Viper intends to distribute the net proceeds from the offering to the Company. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this report does not constitute an offer to sell or a solicitation of any offers to buy these securities.

14. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P and Diamondback O&G are unconditional guarantor's (the "Guarantor Subsidiaries") of the Senior Notes and the second amended and restated credit agreement. On June 23, 2014, in connection with the initial public offering of Viper Energy Partners LP the Company designated the Partnership, its general partner, Viper Energy Partners GP, and the Partnership's subsidiary Viper Energy Partners LLC as unrestricted subsidiaries under the Indenture and upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed consolidated financial information as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 on an issuer (parent company), Guarantor Subsidiaries, Non–Guarantor Subsidiaries and consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
March 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 18,398	$ 6,517	$ 399	$ —	$ 25,314
Accounts receivable	—	47,649	6,631	—	54,280
Accounts receivable - related party	—	2,298	—	—	2,298
Intercompany receivable	985,692	78,635	—	(1,064,327)	—
Intercompany note receivable	440,000	—	—	(440,000)	—
Inventories	—	5,889	—	—	5,889
Deferred income taxes	1,377	—	—	—	1,377
Other current assets	132	1,335	28	—	1,495
Total current assets	1,445,599	142,323	7,058	(1,504,327)	90,653
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	1,614,610	450,961	—	2,065,571
Pipeline and gas gathering assets	—	6,503	—	—	6,503
Other property and equipment	—	4,635	—	—	4,635
Accumulated depletion, depreciation, amortization and impairment	—	(233,543)	(10,766)	1,178	(243,131)
	—	1,392,205	440,195	1,178	1,833,578
Investment in subsidiaries	281,130	—	—	(281,130)	—
Other assets	9,997	2,669	—	—	12,666
Total assets	$ 1,736,726	$ 1,537,197	$ 447,253	$ (1,784,279)	$ 1,936,897
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 24,487	$ —	$ —	$ 24,487
Accounts payable-related party	—	313	—	—	313
Intercompany payable	78,526	985,801	—	(1,064,327)	—
Other current liabilities	18,661	111,338	412	—	130,411
Total current liabilities	97,187	1,121,939	440,412	(1,504,327)	155,211
Long-term debt	450,000	137,000	—	—	587,000
Asset retirement obligations	—	5,147	—	—	5,147
Deferred income taxes	106,630	—	—	—	106,630
Total liabilities	653,817	1,264,086	440,412	(1,504,327)	853,988
Commitments and contingencies					
Stockholders' equity:	1,082,909	273,111	6,841	(279,952)	1,082,909
Total equity	1,082,909	273,111	6,841	(279,952)	1,082,909
Total liabilities and equity	$ 1,736,726	$ 1,537,197	$ 447,253	$ (1,784,279)	$ 1,936,897

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
December 31, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 526	$ 14,267	$ 762	$ —	$ 15,555
Accounts receivable	—	28,544	—	9,426	37,970
Accounts receivable - related party	—	1,303	—	—	1,303
Royalty income receivable	—	—	9,426	(9,426)	—
Intercompany receivable	715,169	413,744	—	(1,128,913)	—
Intercompany note receivable	440,000	—	—	(440,000)	—
Inventories	—	5,631	—	—	5,631
Deferred income taxes	112	—	—	—	112
Other current assets	—	1,397	—	—	1,397
Total current assets	1,155,807	464,886	10,188	(1,568,913)	61,968
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	1,200,326	448,034	—	1,648,360
Pipeline and gas gathering assets	—	6,142	—	—	6,142
Other property and equipment	—	4,071	—	—	4,071
Accumulated depletion, depreciation, amortization and impairment	—	(207,037)	(5,199)	—	(212,236)
	—	1,003,502	442,835	—	1,446,337
Investment in subsidiaries	235,334	—	—	(235,334)	—
Other assets	10,207	3,102	—	—	13,309
Total assets	$ 1,401,348	$ 1,471,490	$ 453,023	$ (1,804,247)	$ 1,521,614
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 2,679	$ —	$ —	$ 2,679
Accounts payable-related party	—	17	—	—	17
Intercompany payable	3,920	1,115,214	87	(1,119,221)	—
Intercompany accrued interest	—	—	9,692	(9,692)	—
Other current liabilities	10,123	108,245	256	—	118,624
Total current liabilities	14,043	1,226,155	10,035	(1,128,913)	121,320
Long-term debt	450,000	10,000	—	—	460,000
Intercompany note payable	—	—	440,000	(440,000)	—
Asset retirement obligations	—	2,989	—	—	2,989
Deferred income taxes	91,764	—	—	—	91,764
Total liabilities	555,807	1,239,144	450,035	(1,568,913)	676,073
Commitments and contingencies					
Stockholders’ equity:	845,541	232,346	2,988	(235,334)	845,541
Total equity	845,541	232,346	2,988	(235,334)	845,541
Total liabilities and equity	$ 1,401,348	$ 1,471,490	$ 453,023	$ (1,804,247)	$ 1,521,614

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended March 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non– Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 75,249	$ —	$ 14,509	$ 89,758
Natural gas sales	—	2,832	—	503	3,335
Natural gas liquid sales	—	4,070	—	841	4,911
Royalty income	—	—	15,853	(15,853)	—
Total revenues	—	82,151	15,853	—	98,004
Costs and expenses:					
Lease operating expenses	—	7,915	—	—	7,915
Production and ad valorem taxes	—	4,903	921	18	5,842
Gathering and transportation	—	588	—	(6)	582
Depreciation, depletion and amortization	—	25,801	5,567	(395)	30,973
General and administrative expenses	3,985	506	66	—	4,557
Asset retirement obligation accretion expense	—	72	—	—	72
Intercompany charges	—	—	78	(78)	—
Total costs and expenses	3,985	39,785	6,632	(461)	49,941
Income (loss) from operations	(3,985)	42,366	9,221	461	48,063
Other income (expense)					
Interest income - intercompany	5,368	—	—	(5,368)	—
Interest expense	(5,887)	(618)	—	—	(6,505)
Interest expense - intercompany	—	—	(5,368)	5,368	—
Other income - intercompany	—	78	—	(78)	—
Other income - related party	—	30	—	—	30
Loss on derivative instruments, net	—	(4,398)	—	—	(4,398)
Total other expense, net	(519)	(4,908)	(5,368)	(78)	(10,873)
Income (loss) before income taxes	(4,504)	37,458	3,853	383	37,190
Provision for income taxes	13,601	—	—	—	13,601
Net income (loss)	$ (18,105)	$ 37,458	$ 3,853	$ 383	$ 23,589

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended March 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 25,253	$ —	$ —	$ 25,253
Natural gas sales	—	1,151	—	—	1,151
Natural gas liquid sales	—	2,505	—	—	2,505
Total revenues	—	28,909	—	—	28,909
Costs and expenses:					
Lease operating expenses	—	5,435	—	—	5,435
Production and ad valorem taxes	—	1,427	—	—	1,427
Gathering and transportation	—	133	—	—	133
Depreciation, depletion and amortization	—	10,738	—	—	10,738
General and administrative expenses	741	1,730	—	—	2,471
Asset retirement obligation accretion expense	—	43	—	—	43
Total costs and expenses	741	19,506	—	—	20,247
Income (loss) from operations	(741)	9,403	—	—	8,662
Other income (expense)					
Interest expense	—	(485)	—	—	(485)
Other income - related party	—	389	—	—	389
Gain (loss) on derivative instruments, net	—	(8)	—	—	(8)
Total other expense, net	—	(104)	—	—	(104)
Income (loss) before income taxes	(741)	9,299	—	—	8,558
Provision for income taxes	3,162	—	—	—	3,162
Net income (loss)	$ (3,903)	$ 9,299	$ —	$ —	$ 5,396

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 11,805	$ 53,416	$ 6,543	$ (298)	$ 71,466
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(79,378)	(6,878)	395	(85,861)
Acquisition of leasehold interests	—	(312,207)	—	—	(312,207)
Intercompany transfers	(204,544)	204,544	—	—	—
Other investing activities	—	(1,116)	—	—	(1,116)
Net cash used in investing activities	(204,544)	(188,157)	(6,878)	395	(399,184)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	127,000	—	—	127,000
Proceeds from public offerings	208,644	—	—	—	208,644
Other financing activities	1,967	(9)	(28)	(97)	1,833
Net cash provided by (used in) financing activities	210,611	126,991	(28)	(97)	337,477
Net increase in cash and cash equivalents	17,872	(7,750)	(363)	—	9,759
Cash and cash equivalents at beginning of period	526	14,267	762	—	15,555
Cash and cash equivalents at end of period	$ 18,398	$ 6,517	$ 399	$ —	$ 25,314

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Three Months Ended March 31, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ (5)	$ 16,860	$ —	$ —	$ 16,855
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(54,962)	—	—	(54,962)
Acquisition of leasehold interests	—	(18,550)	—	—	(18,550)
Other investing activities	—	(582)	—	—	(582)
Net cash used in investing activities	—	(74,094)	—	—	(74,094)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	36,500	—	—	36,500
Intercompany transfers	103	(103)	—	—	—
Other financing activities	(103)	—	—	—	(103)
Net cash provided by (used in) financing activities	—	36,397	—	—	36,397
Net increase in cash and cash equivalents	(5)	(20,837)	—	—	(20,842)
Cash and cash equivalents at beginning of period	14	26,344	—	—	26,358
Cash and cash equivalents at end of period	$ 9	$ 5,507	$ —	$ —	$ 5,516

Exhibit 99.5

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(Unaudited)

Diamondback Energy, Inc. and Subsidiaries
Consolidated Balance Sheets
(Unaudited)

	June 30, 2014	December 31, 2013
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$ 36,993	$ 15,555
Accounts receivable:		
Joint interest and other	24,697	14,437
Oil and natural gas sales	40,648	23,533
Related party	3,310	1,303
Inventories	3,308	5,631
Deferred income taxes	4,327	112
Derivative instruments	—	213
Prepaid expenses and other	1,421	1,184
Total current assets	114,704	61,968
Property and equipment		
Oil and natural gas properties, based on the full cost method of accounting ($456,692 and $369,561 excluded from amortization at June 30, 2014 and December 31, 2013, respectively)	2,191,321	1,648,360
Pipeline and gas gathering assets	6,846	6,142
Other property and equipment	4,973	4,071
Accumulated depletion, depreciation, amortization and impairment	(283,152)	(212,236)
	1,919,988	1,446,337
Derivative instruments	—	218
Other assets	12,702	13,091
Total assets	$ 2,047,394	$ 1,521,614
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$ 23,475	$ 2,679
Accounts payable-related party	67	17
Accrued capital expenditures	81,550	74,649
Other accrued liabilities	38,236	34,750
Revenues and royalties payable	15,170	9,225
Derivative instruments	10,379	—
Total current liabilities	168,877	121,320
Long-term debt	496,000	460,000
Asset retirement obligations	5,437	2,989
Deferred income taxes	124,743	91,764
Total liabilities	795,057	676,073
Contingencies (Note 13)		
Stockholders' equity:		
Common stock, $0.01 par value, 100,000,000 shares authorized, 50,807,635 issued and outstanding at June 30, 2014; 47,106,216 issued and outstanding at December 31, 2013	509	471
Additional paid-in capital	1,060,537	842,557
Retained earnings	53,855	2,513
Total Diamondback Energy, Inc. stockholders' equity	1,114,901	845,541
Noncontrolling interest	137,436	—
Total equity	1,252,337	845,541
Total liabilities and equity	$ 2,047,394	$ 1,521,614

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per share amounts)			
Revenues:				
Oil sales	$ 115,282	$ 41,034	$ 205,040	$ 66,287
Natural gas sales	1,913	988	3,668	1,727
Natural gas sales - related party	2,416	680	3,996	1,092
Natural gas liquid sales	3,304	1,649	5,888	3,471
Natural gas liquid sales - related party	4,089	1,043	6,416	1,726
Total revenues	127,004	45,394	225,008	74,303
Costs and expenses:				
Lease operating expenses	10,425	5,103	18,232	9,809
Lease operating expenses - related party	71	392	179	594
Production and ad valorem taxes	8,106	2,672	13,684	4,550
Production and ad valorem taxes - related party	448	116	712	192
Gathering and transportation	102	31	316	106
Gathering and transportation - related party	601	216	969	274
Depreciation, depletion and amortization	40,021	14,815	70,994	25,553
General and administrative expenses (including non-cash stock based compensation, net of capitalized amounts, of $1,128 and $477 for the three months ended June 30, 2014 and 2013, respectively, and $3,318 and $936 for the six months ended June 30, 2014 and 2013, respectively)	3,610	2,355	7,875	4,540
General and administrative expenses - related party	324	266	616	552
Asset retirement obligation accretion expense	104	45	176	88
Total costs and expenses	63,812	26,011	113,753	46,258
Income from operations	63,192	19,383	111,255	28,045
Other income (expense)				
Interest expense	(7,739)	(535)	(14,244)	(1,020)
Other income - related party	30	388	60	777
Other expense	(1,408)	—	(1,408)	—
Gain (loss) on derivative instruments, net	(11,088)	3,037	(15,486)	3,029
Total other income (expense), net	(20,205)	2,890	(31,078)	2,786
Income before income taxes	42,987	22,273	80,177	30,831
Provision for income taxes				
Deferred	15,163	7,802	28,764	10,964
Net income	27,824	14,471	51,413	19,867
Less: Net income attributable to noncontrolling interest	71	—	71	—
Net income attributable to Diamondback Energy, Inc.	$ 27,753	$ 14,471	$ 51,342	$ 19,867
Earnings per common share				
Basic	$ 0.55	$ 0.37	$ 1.03	$ 0.52
Diluted	$ 0.54	$ 0.36	$ 1.02	$ 0.52
Weighted average common shares outstanding				
Basic	50,777	39,402	49,622	38,237
Diluted	51,142	39,719	50,047	38,477

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statement of Stockholders' Equity
(Unaudited)

	Common Stock		Additional Paid-in	Retained	Non-controlling	
	Shares	Amount	Capital	Earnings	Interest	Total
	(In thousands)					
Balance December 31, 2013	47,106	$ 471	$ 842,557	$ 2,513	$ —	$ 845,541
Net proceeds from issuance of common units - Viper Energy Partners LP	—	—	—	—	137,365	137,365
Stock based compensation	—	—	5,906	—	—	5,906
Common shares issued in public offering, net of offering costs	3,450	35	208,394	—	—	208,429
Exercise of stock options and vesting of restricted stock units	251	3	3,680	—	—	3,683
Net income	—	—	—	51,342	71	51,413
Balance June 30, 2014	50,807	$ 509	$ 1,060,537	$ 53,855	$ 137,436	$ 1,252,337

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows
(Unaudited)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 51,413	$ 19,867
Adjustments to reconcile net income to net cash provided by operating activities:		
Provision for deferred income taxes	28,764	10,964
Asset retirement obligation accretion expense	176	88
Depreciation, depletion, and amortization	70,994	25,553
Amortization of debt issuance costs	946	318
Change in fair value of derivative instruments	10,810	(5,429)
Stock based compensation expense	3,318	936
(Gain) loss on sale of assets, net	1,397	(30)
Changes in operating assets and liabilities:		
Accounts receivable	(18,584)	(12,185)
Accounts receivable-related party	(2,007)	5,110
Inventories	977	(96)
Prepaid expenses and other	(219)	(1,517)
Accounts payable and accrued liabilities	2,076	4,543
Accounts payable and accrued liabilities-related party	—	(74)
Accrued interest	3,415	—
Revenues and royalties payable	6,230	1,750
Net cash provided by operating activities	159,706	49,798
Cash flows from investing activities:		
Additions to oil and natural gas properties	(206,779)	(102,785)
Additions to oil and natural gas properties-related party	(2,571)	(9,298)
Acquisition of Gulfport properties	—	(18,550)
Acquisition of leasehold interests	(312,207)	(6,192)
Pipeline and gas gathering assets	(1,165)	—
Purchase of other property and equipment	(934)	(1,615)
Proceeds from sale of property and equipment	11	54
Settlement of non-hedge derivative instruments	—	(289)
Net cash used in investing activities	(523,645)	(138,675)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	166,000	49,000
Repayment on credit facility	(130,000)	(49,000)
Debt issuance costs	(1,039)	(72)
Public offering costs	(946)	(447)
Proceeds from public offerings	347,679	144,936
Exercise of stock options	3,683	—
Net cash provided by financing activities	385,377	144,417
Net increase in cash and cash equivalents	21,438	55,540
Cash and cash equivalents at beginning of period	15,555	26,358
Cash and cash equivalents at end of period	$ 36,993	$ 81,898

Diamondback Energy, Inc. and Subsidiaries
Consolidated Statements of Cash Flows - Continued
(Unaudited)

See accompanying notes to consolidated financial statements.

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$ 11,409	$ 383
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$ 382	$ 111
Asset retirement obligation revisions in estimated liability	$ 588	$ —
Asset retirement obligation acquired	$ 1,312	$ —
Change in accrued capital expenditures	$ 6,901	$ 20,645
Capitalized stock based compensation	$ 2,715	$ 420

See accompanying notes to consolidated financial statements.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements
(Unaudited)

1. DESCRIPTION OF THE BUSINESS AND BASIS OF PRESENTATION

Organization and Description of the Business

Diamondback Energy, Inc. (“Diamondback” or the “Company”) together with its subsidiaries, is an independent oil and gas company currently focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Diamondback was incorporated in Delaware on December 30, 2011.

On June 17, 2014, Diamondback entered into a contribution agreement (the “Contribution Agreement”) with Viper Energy Partners LP (the “Partnership”), Viper Energy Partners GP LLC (the “General Partner”) and Viper Energy Partners LLC to transfer Diamondback’s ownership interest in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units, representing an approximate 92% limited partner interest in the Partnership. Diamondback also owns and controls the General Partner, which holds a non-economic general partner interest in the Partnership. On June 23, 2014, the Partnership completed its initial public offering (the “Viper Offering”) of 5,750,000 common units. See Note 4—Viper Energy Partners LP for additional information regarding the Partnership.

The wholly owned subsidiaries of Diamondback, as of June 30, 2014, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, and Viper Energy Partners GP LLC, a Delaware limited liability company. The consolidated subsidiaries include the wholly owned subsidiaries as well as Viper Energy Partners LP, a Delaware limited partnership and Viper Energy Partners LLC, a Delaware limited liability company. Noncontrolling interests represent third-party ownership in the net assets of the consolidated Partnership.

Basis of Presentation

The consolidated financial statements include the accounts of the Company and its subsidiaries after all significant intercompany balances and transactions have been eliminated upon consolidation.

The Partnership is consolidated in the financial statements of the Company. As of June 30, 2014, the Company owned approximately 92% of the common units of the Partnership, Wexford Capital LP (“Wexford”) owned approximately 1% and third party investors owned the remaining approximate 7% of the common units of the Partnership. The third party limited partnership interests in the Partnership are included in “noncontrolling interest” reported on the consolidated balance sheet.

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of the Securities and Exchange Commission (the “SEC”). They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results for interim periods, on a basis consistent with the annual audited financial statements. All such adjustments are of a normal recurring nature. Certain information, accounting policies and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to such rules and regulations, although the Company believes the disclosures are adequate to make the information presented not misleading. This Quarterly Report on Form 10–Q should be read in conjunction with the Company’s most recent Annual Report on Form 10–K for the fiscal year ended December 31, 2013, which contains a summary of the Company’s significant accounting policies and other disclosures.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

Certain amounts included in or affecting the Company’s consolidated financial statements and related disclosures must be estimated by management, requiring certain assumptions to be made with respect to values or conditions that cannot be known with certainty at the time the consolidated financial statements are prepared. These estimates and assumptions affect the amounts the Company reports for assets and liabilities and the Company’s disclosure of contingent assets and liabilities at the date of the consolidated financial statements. Actual results could differ from those estimates.

The Company evaluates these estimates on an ongoing basis, using historical experience, consultation with experts and other methods the Company considers reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the Company's estimates. Any effects on the Company's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. Significant items subject to such estimates and assumptions include estimates of proved oil and natural gas reserves and related present value estimates of future net cash flows therefrom, the carrying value of oil and natural gas properties, asset retirement obligations, the fair value determination of acquired assets and liabilities, stock-based compensation, fair value estimates of commodity derivatives and estimates of income taxes.

3. ACQUISITIONS

2014 Activity

On February 27 and 28, 2014, the Company completed acquisitions of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 6,450 gross (4,785 net) acres with a 74% working interest (56% net revenue interest). The acquisitions were accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. These acquisitions were funded in part by the net proceeds of the February 2014 equity offering discussed in Note 8 below.

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition dates. The aggregate consideration transferred was $292,159,000 in cash, subject to post-closing adjustments, resulting in no goodwill or bargain purchase gain.

		(in thousands)
Proved oil and natural gas properties	$	170,174
Unevaluated oil and natural gas properties		123,243
Asset retirement obligations		(1,258)
Total fair value of net assets	$	292,159

The Company has included in its consolidated statements of operations revenues of $19,183,000 and direct operating expenses of $4,601,000 for the period from February 28, 2014 to June 30, 2014 due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion. The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three months and six months ended June 30, 2014 and 2013 have been prepared to give effect to the February 2014 acquisitions as if they had occurred on January 1, 2013. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2013. The pro forma data also necessarily exclude various operation expenses related to the properties and the financial statements should not be viewed as indicative of operations in future periods.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2014		2013		2014		2013	
	(Pro Forma) (in thousands, except per share amounts)							
Revenues	$	127,004	$	62,209	$	234,983	$	106,600
Income from operations		63,192		26,872		115,385		41,527
Net income		27,823		19,337		54,033		28,511
Basic earnings per common share	$	0.55	$	0.49	$	1.09	$	0.75
Diluted earnings per common share	$	0.54	$	0.49	$	1.08	$	0.74

2013 Activity

In September 2013, the Company completed two separate acquisitions of additional leasehold interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $165.0 million, subject to certain adjustments. The first of these acquisitions closed on September 4, 2013 when the Company acquired certain assets located in northwestern Martin County, Texas, consisting of a 100% working interest (80% net revenue interest) in 4,506 gross and net acres. The second of these acquisitions closed on September 26, 2013, when the Company acquired certain assets located primarily in southwestern Dawson County, Texas, consisting of a 71% working interest (55% net revenue interest) in 9,390 gross (6,638 net) acres. These acquisitions were funded with a portion of the net proceeds from the August 2013 equity offering discussed in Note 8 below.

On September 19, 2013, the Company completed the acquisition of the mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin. As part of the closing of the acquisition, the mineral interests were conveyed from the previous owners to Viper Energy Partners LLC and, subsequently, were contributed to the Partnership on June 17, 2014. See Note 4—Viper Energy Partners LP for additional information regarding the Partnership. The mineral interests entitle the holder of such interests to receive an average 21.4% royalty interest on all production from this acreage with no additional future capital or operating expense required. The $440.0 million purchase price was funded with the net proceeds of the Company’s offering of Senior Notes discussed in Note 7 below.

4. VIPER ENERGY PARTNERS LP

The Partnership is a publicly traded Delaware limited partnership, the common units of which are listed on the NASDAQ Global Market under the symbol “VNOM”. The Partnership was formed by Diamondback on February 27, 2014, to, among other things, own, acquire and exploit oil and natural gas properties in North America. The Partnership is currently focused on oil and natural gas properties in the Permian Basin.

Prior to the completion on June 23, 2014 of the Viper Offering, Diamondback owned all of the general and limited partner interests in the Partnership. The Viper Offering consisted of 5,750,000 common units representing approximately 8% of the limited partner interests in the Partnership at a price to the public of $26.00 per common unit, which included 750,000 common units issued pursuant to an option to purchase additional common units granted to the underwriters on the same terms. The Partnership received net proceeds of approximately $137.2 million from the sale of these common units, net of offering expenses and underwriting discounts and commissions.

In connection with the Viper Offering, Diamondback contributed all of the membership interests in Viper Energy Partners LLC to the Partnership in exchange for 70,450,000 common units. In addition, in connection with the closing of the Viper Offering, the Partnership agreed to distribute to Diamondback all cash and cash equivalents and the royalty income receivable on hand in the aggregate amount of approximately $11.3 million and the net proceeds from the Viper Offering. As of June 30, 2014, the Partnership had distributed $137.5 million to Diamondback and the Partnership recorded a payable balance of approximately $11.3 million. The contribution of Viper Energy Partners LLC to the Partnership was accounted for as a combination of entities under common control with assets and liabilities transferred at their carrying amounts in a manner similar to a pooling of interests.

The Company has also entered into the following agreements with the Partnership:

Partnership Agreement

In connection with the closing of the Viper Offering, the General Partner and Diamondback entered into the first amended and restated agreement of limited partnership (the “Partnership Agreement”), dated June 23, 2014. The Partnership Agreement requires the Partnership to reimburse the General Partner for all direct and indirect expenses incurred or paid on the Partnership’s behalf and all other expenses allocable to the Partnership or otherwise incurred by the General Partner in connection with operating the Partnership’s business. The Partnership Agreement does not set a limit on the amount of expenses for which the General Partner and its affiliates may be reimbursed. These expenses include salary, bonus, incentive compensation and other amounts paid to persons who perform services for the Partnership or on its behalf and expenses allocated to the General Partner by its affiliates. The General Partner is entitled to determine the expenses that are allocable to the Partnership.

Tax Sharing

In connection with the closing of the Viper Offering, the Partnership entered into a tax sharing agreement (the “Tax Sharing Agreement”) with Diamondback pursuant to which the Partnership will reimburse Diamondback for its share of state and local income and other taxes for which the Partnership’s results are included in a combined or consolidated tax return filed by Diamondback with respect to taxable periods including or beginning on June 23, 2014. The amount of any such reimbursement is limited to the tax the Partnership would have paid had it not been included in a combined group with Diamondback. Diamondback may use its tax attributes to cause its combined or consolidated group, of which the Partnership may be a member for this purpose, to owe less or no tax. In such a situation, the Partnership would reimburse Diamondback for the tax the Partnership would have owed had the tax attributes not been available or used for the Partnership’s benefit, even though Diamondback had no cash tax expense for that period.

See Note 10—Related Party Transactions for details of the the advisory services agreement the Partnership and General Partner entered into with Wexford.

The Partnership has entered into a secured revolving credit facility with Wells Fargo Bank, National Association, (“Wells Fargo”) as administrative agent sole book runner and lead arranger. See Note 7—Debt for a description of this credit facility

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	June 30, 2014	December 31, 2013
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$ 1,734,629	$ 1,278,799
Not subject to depletion-acquisition costs		
Incurred in 2014	144,516	—
Incurred in 2013	237,540	279,353
Incurred in 2012	73,872	87,252
Incurred in 2011	764	1,598
Incurred in 2010	—	1,358
Total not subject to depletion	456,692	369,561
Gross oil and natural gas properties	2,191,321	1,648,360
Less accumulated depreciation, depletion, amortization and impairment	(281,218)	(210,837)
Oil and natural gas properties, net	1,910,103	1,437,523
Pipeline and gas gathering assets	6,846	6,142
Other property and equipment	4,973	4,071
Less accumulated depreciation	(1,934)	(1,399)
Other property and equipment, net	3,039	2,672
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$ 1,919,988	$ 1,446,337

The average depletion rate per barrel equivalent unit of production was $24.46 and $24.81 for the three months and six months ended June 30, 2014, respectively, and $24.42 and $24.44 for the three months and six months ended June 30, 2013, respectively. Internal costs capitalized to the full cost pool represent management’s estimate of costs incurred directly related to exploration and development activities such as geological and other administrative costs associated with overseeing the exploration and development activities. All internal costs not directly associated with exploration and development activities were charged to expense as they were incurred. Capitalized internal costs were approximately $2,632,000 and $4,928,000 for the three months and six months ended June 30, 2014, respectively, and $843,000 and $1,640,000 for the three months and six months ended June 30, 2013, respectively. Costs associated with unevaluated properties are excluded from the full cost pool until the Company has made a determination as to the existence of proved reserves. The inclusion of the Company’s unevaluated costs into the amortization base is expected to be completed within three to five years.

6. ASSET RETIREMENT OBLIGATIONS

The following table describes the changes to the Company's asset retirement obligation liability for the following periods:

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
	(in thousands)	
Asset retirement obligation, beginning of period	$ 3,029	$ 2,145
Additional liability incurred	382	111
Liabilities acquired	1,312	—
Liabilities settled	(10)	—
Accretion expense	176	88
Revisions in estimated liabilities	588	—
Asset retirement obligation, end of period	5,477	2,344
Less current portion	40	20
Asset retirement obligations - long-term	$ 5,437	$ 2,324

The Company's asset retirement obligations primarily relate to the future plugging and abandonment of wells and related facilities. The Company estimates the future plugging and abandonment costs of wells, the ultimate productive life of the properties, a risk-adjusted discount rate and an inflation factor in order to determine the current present value of this obligation. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation liability, a corresponding adjustment is made to the oil and natural gas property balance.

7. DEBT

Long-term debt consisted of the following as of the dates indicated:

	June 30, 2014	December 31, 2013
	(in thousands)	
Revolving credit facility	$ 46,000	$ 10,000
7.625 % Senior Notes due 2021	450,000	450,000
Total long-term debt	$ 496,000	$ 460,000

Senior Notes

On September 18, 2013, the Company completed an offering of $450.0 million in aggregate principal amount of 7.625% senior unsecured notes due 2021 (the "Senior Notes"). The Senior Notes bear interest at the rate of 7.625% per annum, payable semi-annually, in arrears on April 1 and October 1 of each year, commencing on April 1, 2014 and will mature on October 1, 2021. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries and, upon such designation, Viper Energy LLC, which was a guarantor under the indenture governing of the Senior Notes, was released as a guarantor under the indenture. As a result, the Senior Notes are now fully and unconditionally guaranteed by Diamondback O&G LLC and Diamondback E&P LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The net proceeds from the Senior Notes were used to fund the acquisition of mineral interests underlying approximately 14,804 gross (12,687 net) acres in Midland County, Texas in the Permian Basin.

The Senior Notes were issued under, and are governed by, an indenture among the Company, the subsidiary guarantors party thereto and Wells Fargo Bank, N.A., as the trustee (the "Indenture"). The Indenture contains certain covenants that, subject to certain exceptions and qualifications, among other things, limit the Company's ability and the ability of the restricted subsidiaries to incur or guarantee additional indebtedness, make certain investments, declare or pay dividends or make other distributions on, or redeem or repurchase, capital stock, prepay subordinated indebtedness, sell assets including capital stock of subsidiaries, agree to payment restrictions affecting the Company's restricted subsidiaries, consolidate, merge, sell or otherwise dispose of all or substantially all of its assets, enter into transactions with affiliates, incur liens, engage in business other than the oil and gas business and designate certain of the Company's subsidiaries as unrestricted subsidiaries. If the Company experiences certain kinds of changes of control or if it sells certain of its assets, holders of the Senior Notes may have the right to require the Company to repurchase their Senior Notes.

The Company will have the option to redeem the Senior Notes, in whole or in part, at any time on or after October 1, 2016 at the redemption prices (expressed as percentages of principal amount) of 105.719% for the 12-month period beginning on October 1, 2016, 103.813% for the 12-month period beginning on October 1, 2017, 101.906% for the 12-month period beginning on October 1, 2018 and 100.000% beginning on October 1, 2019 and at any time thereafter with any accrued and unpaid interest to, but not including, the date of redemption. In addition, prior to October 1, 2016, the Company may redeem all or a part of the Senior Notes at a price equal to 100% of the principal amount thereof, plus accrued and unpaid interest, if any, to the redemption date, plus a "make-whole" premium at the redemption date. Furthermore, before October 1, 2016, the Company may, at any time or from time to time, redeem up to 35% of the aggregate principal amount of the Senior Notes with the net cash proceeds of certain equity offerings at a redemption price of 107.625% of the principal amount of the Senior Notes being redeemed plus any accrued and unpaid interest to the date of redemption, if at least 65% of the aggregate principal amount of the Senior Notes originally issued under the Indenture remains outstanding immediately after such redemption and the redemption occurs within 120 days of the closing date of such equity offering.

In connection with the issuance of the Senior Notes, the Company and the subsidiary guarantors entered into a Registration Rights Agreement (the "Registration Rights Agreement") with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors have agreed to file a registration statement with respect to an offer to exchange the Senior Notes for a new issue of substantially identical debt securities registered under the Securities Act, which registration statement was filed with the SEC on March 14, 2014. Under the Registration Rights Agreement, the Company also agreed to use its commercially reasonable efforts to cause the exchange offer registration statement to become effective within 360 days after the issue date of the Senior Notes and to consummate the exchange offer 30 days after effectiveness. The Company may be required to file a shelf registration statement to cover resales of the Senior Notes under certain circumstances. If the Company fails to satisfy certain of its obligations under the Registration Rights Agreement, the Company agreed to pay additional interest to the holders of the Senior Notes as specified in the Registration Rights Agreement.

Credit Facility-Wells Fargo Bank

The Company's secured second amended and restated credit agreement, dated November 1, 2013, with a syndication of banks, including Wells Fargo as administrative agent sole book runner and lead arranger, provides for a revolving credit facility in the maximum amount of $600.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Company's oil and natural gas reserves and other factors (the "borrowing base"). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of June 30, 2014, the borrowing base was set at $350.0 million and the Company had outstanding borrowings of $46.0 million.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Company that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Company is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of November 1, 2018.

On June 9, 2014, Diamondback entered into a first amendment (the "First Amendment") to the second amended and restated credit agreement, dated November 1, 2013. The First Amendment modified certain provisions of the credit agreement to, among other things, allow the Company to designate one or more of our subsidiaries as "Unrestricted

Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy LLC as unrestricted subsidiaries under the credit agreement and, upon such designation, Viper Energy LLC, which was a guarantor under the Indenture, was released as a guarantor under the Indenture. As a result, the loan is now secured by substantially all of the assets of the Company, Diamondback E&P LLC and Diamondback O&G LLC and will also be secured by any future restricted subsidiaries of Diamondback.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $750.0 million in the form of senior or senior subordinated notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid. As of June 30, 2014, the Company had $450.0 million of senior unsecured notes outstanding.

As of June 30, 2014 and December 31, 2013, the Company was in compliance with all financial covenants under its revolving credit facility, as then in effect. The lenders may accelerate all of the indebtedness under the Company’s revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

Partnership Credit Facility-Wells Fargo Bank

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The credit agreement provides for a revolving credit facility in the maximum amount of $500.0 million, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on the Partnership’s oil and natural gas reserves and other factors (the “borrowing base”). The borrowing base is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of July 8, 2014, the borrowing base was set at $110.0 million, and Wells Fargo was the only lender under the credit agreement, with a maximum credit amount of $55.0 million. Under the credit agreement, the commitment of the lenders is equal to the lessor of the aggregate maximum credit amounts of the lenders and the borrowing base. As of August 6, 2014, the borrowing base was increased to $110.0 million with Wells Fargo as the only lender under the credit agreement. The Partnership had outstanding borrowings of $50.0 million as of August 6, 2014.

The outstanding borrowings under the credit agreement bear interest at a rate elected by the Partnership that is equal to an alternative base rate (which is equal to the greatest of the prime rate, the Federal Funds effective rate plus 0.5% and 3-month LIBOR plus 1.0%) or LIBOR, in each case plus the applicable margin. The applicable margin ranges from 0.5% to 1.50% in the case of the alternative base rate and from 1.50% to 2.50% in the case of LIBOR, in each case depending on the amount of the loan outstanding in relation to the borrowing base. The Partnership is obligated to pay a quarterly commitment fee ranging from 0.375% to 0.500% per year on the unused portion of the borrowing base, which fee is also dependent on the amount of the loan outstanding in relation to the borrowing base. Loan principal may be optionally repaid from time to time without premium or penalty (other than customary LIBOR breakage), and is required to be paid (a) if the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period) and (b) at the maturity date of July 8, 2019. The loan is secured by substantially all of the assets of the Partnership and its subsidiaries.

The credit agreement contains various affirmative, negative and financial maintenance covenants. These covenants, among other things, limit additional indebtedness, additional liens, sales of assets, mergers and consolidations, dividends and distributions, transactions with affiliates and entering into certain swap agreements and require the maintenance of the financial ratios described below.

Financial Covenant	Required Ratio
Ratio of total debt to EBITDAX	Not greater than 4.0 to 1.0
Ratio of current assets to liabilities, as defined in the credit agreement	Not less than 1.0 to 1.0
EBITDAX will be annualized beginning with the quarter ending September 30, 2014 and ending with the quarter ended March 31, 2015	

The covenant prohibiting additional indebtedness allows for the issuance of unsecured debt of up to $250.0 million in the form of senior unsecured notes and, in connection with any such issuance, the reduction of the borrowing base by 25% of the stated principal amount of each such issuance. A borrowing base reduction in connection with such issuance may require a portion of the outstanding principal of the loan to be repaid.

The lenders may accelerate all of the indebtedness under the Partnership’s revolving credit facility upon the occurrence and during the continuance of any event of default. The credit agreement contains customary events of default, including non-payment, breach of covenants, materially incorrect representations, cross-default, bankruptcy and change of control. There are no cure periods for events of default due to non-payment of principal and breaches of negative and financial covenants, but non-payment of interest and breaches of certain affirmative covenants are subject to customary cure periods.

8. CAPITAL STOCK AND EARNINGS PER SHARE

As of June 30, 2014, Diamondback had completed the following equity offerings since the closing of its initial public offering on October 17, 2012:

On May 21, 2013, the Company completed an underwritten primary public offering of 5,175,000 shares of common stock, which included 675,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $29.25 per share and the Company received net proceeds of approximately $144.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2013, the Company completed an underwritten public offering of 4,600,000 shares of common stock, which included 600,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $40.25 per share and the Company received net proceeds of approximately $177.5 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In February 2014, the Company completed an underwritten public offering of 3,450,000 shares of common stock, which included 450,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $62.67 per share and the Company received net proceeds of approximately $208.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Earnings Per Share

The Company’s basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period. Diluted earnings per share include the effect of potentially dilutive shares outstanding for the period. Additionally, for the diluted earnings per share computation, the per share earnings of the Partnership are included in the consolidated earnings per share computation based on the consolidated group's holdings of the subsidiary. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Three Months Ended June 30,					
	2014			2013		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					
Basic:						
Net income attributable to common stock	$ 27,753	50,777	$ 0.55	14,471	39,402	$ 0.37
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$ (74)	365		—	317	
Diluted:						
Net income attributable to common stock	$ 27,679	51,142	$ 0.54	14,471	39,719	$ 0.36

	Six Months Ended June 30,					
	2014			2013		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					
Basic:						
Net income attributable to common stock	$ 51,342	49,622	$ 1.03	19,867	38,237	$ 0.52
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$ (74)	425		—	240	
Diluted:						
Net income attributable to common stock	$ 51,268	50,047	$ 1.02	19,867	38,477	$ 0.52

9. STOCK BASED COMPENSATION

For the three months and six months ended June 30, 2014, the Company incurred $2,777,000 and $6,033,000, respectively, of stock based compensation, of which the Company capitalized $1,649,000 and $2,715,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties. For the three months and six months ended June 30, 2013, the Company incurred $700,000 and $1,356,000, respectively, of stock based compensation, of which the Company capitalized $223,000 and $420,000, respectively, pursuant to the full cost method of accounting for oil and natural gas properties.

On June 17, 2014, in connection with the Viper Offering, the Board of Directors of the General Partner adopted the Viper Energy Partners LP Long Term Incentive Plan (“Viper LTIP”), effective June 17, 2014, for employees, officers, consultants and directors of the General Partner and any of its affiliates, including Diamondback, who perform services for the Partnership. The Viper LTIP provides for the grant of unit options, unit appreciation rights, restricted units, unit awards, phantom units, distribution equivalent rights, cash awards, performance awards, other unit-based awards and substitute awards. A total of 9,144,000 common units has been reserved for issuance pursuant to the Viper LTIP. Common units that are cancelled, forfeited or withheld to satisfy exercise prices or tax withholding obligations will be available for delivery pursuant to other awards. The Viper LTIP is administered by the Board of Directors of the General Partner or a committee thereof.

Stock Options

The following table presents the Company’s stock option activity under the 2012 Plan for the six months ended June 30, 2014.

		Weighted Average			
	Options	Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	712,955	$ 17.96		
Granted	—	$ —		
Exercised	(205,750)	$ 17.90		
Expired/Forfeited	—	$ —		
Outstanding at June 30, 2014	507,205	$ 17.99	2.23	$ 28,076
Vested and Expected to vest at June 30, 2014	507,205	$ 17.99	2.23	$ 28,076
Exercisable at June 30, 2014	134,955	$ 17.50	1.62	$ 7,536

The aggregate intrinsic value of stock options that were exercised during the six months ended June 30, 2014 was $10,659,000. As of June 30, 2014, the unrecognized compensation cost related to unvested stock options was $1,212,000. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the 2012 Plan during the six months ended June 30, 2014.

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	132,499	$ 19.20
Granted	106,550	$ 62.03
Vested	(45,669)	$ 47.69
Forfeited	(900)	$ 41.66
Unvested at June 30, 2014	192,480	$ 36.04

The aggregate fair value of restricted stock units that vested during the six months ended June 30, 2014 was $3,051,000. As of June 30, 2014, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $5,081,000. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

Performance Based Restricted Stock Units

To provide long-term incentives for the executive officers to deliver competitive returns to the Company's stockholders, the Company has granted performance based restricted stock units to eligible employees. The ultimate number of shares awarded from these conditional restricted stock units is based upon measurement of total stockholder return of the Company's common stock ("TSR") as compared to a designated peer group during a three-year performance period. In February 2014, eligible employees received initial performance restricted stock unit awards totaling 79,150 units from which a minimum of 0% and a maximum of 200% units could be awarded. The awards have a performance period of January 1, 2013 to December 31, 2015 and cliff vest at December 31, 2015. There were no performance restricted stock units issued or outstanding during the six months ended June 30, 2013.

The fair value of each performance restricted stock unit is estimated at the date of grant using a Monte Carlo simulation, which results in an expected percentage of units to be earned during the performance period. The following table presents a summary of the grant-date fair values of performance restricted stock units granted and the related assumptions.

	2014
Grant-date fair value	$ 125.63
Risk-free rate	0.30%
Company volatility	39.60%

The following table presents the Company’s performance restricted stock units activity under the 2012 Plan for the six months ended June 30, 2014.

	Performance Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2013	—	$ —
Granted	79,150	$ 125.63
Vested	—	$ —
Forfeited	—	$ —
Unvested at June 30, 2014 [(1)]	79,150	$ 125.63

(1) A maximum of 158,300 units could be awarded based upon the Company’s final TSR ranking.

As of June 30, 2014, the Company’s unrecognized compensation cost related to unvested performance based restricted stock awards and units was $8,111,000. Such cost is expected to be recognized over a weighted-average period of 1.5 years.

Partnership Unit Options

In accordance with the Viper LTIP, the exercise price of unit options granted may not be less than the market value of the common units at the date of grant. The units issued under the Viper LTIP will consist of new common units of the Partnership. On June 17, 2014, the Board of Directors of the General Partner granted 2,500,000 unit options to our executive officers of the General Partner. The unit options vest approximately 33% ratably on each of the next three anniversaries of the date of grant. In the event the fair market value per unit as of the exercise date is less than the exercise price per option unit then the vested options will automatically terminate and become null and void as of the exercise date.

The fair value of the unit options on the date of grant is expensed over the applicable vesting period. The Partnership estimates the fair values of unit options granted using a Black-Scholes option valuation model, which requires the Partnership to make several assumptions. At the time of grant the Partnership did not have a history of market prices, thus the expected volatility was determined using the historical volatility for a peer group of companies. The expected term of options granted was determined based on the contractual term of the awards. The risk-free interest rate is based on the U.S. treasury yield curve rate for the expected term of the unit option at the date of grant. The expected dividend yield was based upon projected performance of the Partnership.

	2014
Grant-date fair value	$ 4.24
Expected volatility	36.0%
Expected dividend yield	5.9%
Expected term (in years)	3.0
Risk-free rate	0.99%

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The following table presents the unit option activity under the Viper LTIP for the six months ended June 30, 2014.

		Weighted Average		
	Unit Options	Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2013	—	$ —		
Granted	2,500,000	$ 26.00		
Outstanding at June 30, 2014	2,500,000	$ 26.00	2.97	$ 19,500
Vested and Expected to vest at June 30, 2014	2,500,000	$ 26.00	2.97	$ 19,500
Exercisable at June 30, 2014	—	$ —	—	$ —

As of June 30, 2014, the unrecognized compensation cost related to unvested unit options was $10,472,000. Such cost is expected to be recognized over a weighted-average period of 3.0 years.

10. RELATED PARTY TRANSACTIONS

Administrative Services

An entity under common management provided technical, administrative and payroll services to the Company under a shared services agreement which began March 1, 2008. The initial term of this shared service agreement was two years. Since the expiration of such two-year period on March 1, 2010, the agreement, by its terms has continued on a month-to-month basis. For the three months and six months ended June 30, 2014, the Company incurred total costs of $1,000 and $2,000, respectively. For the three months and six months ended June 30, 2013, the Company incurred total costs of $51,000 and $109,000, respectively. Costs incurred unrelated to drilling activities are expensed and costs incurred in the acquisition, exploration and development of proved oil and natural gas properties have been capitalized. As of June 30, 2014 and December 31, 2013, the Company owed the administrative services affiliate no amounts and $17,000, respectively. These amounts are included in accounts payable-related party in the accompanying consolidated balance sheets.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provides this entity and, at its request, certain affiliates, with consulting, technical and administrative services. The initial term of the additional shared services agreement was two years. The agreement now continues on a month-to-month basis until canceled by either party upon thirty days prior written notice. Costs that are attributable to and billed to other affiliates are reported as other income-related party. For the three months and six months ended June 30, 2014, the affiliate reimbursed the Company $30,000 and $60,000, respectively, and for the three months and six months ended June 30, 2013, the affiliate reimbursed the Company $388,000 and $777,000, respectively, for services under the shared services agreement. As of June 30, 2014 and December 31, 2013, the affiliate owed the Company no amounts for either period.

Drilling Services

Bison Drilling and Field Services LLC (“Bison”), an entity controlled by Wexford, has performed drilling and field services for the Company under master drilling and field service agreements. Under the Company’s most recent master drilling agreement with Bison, effective as of January 1, 2013, Bison committed to accept orders from the Company for the use of at least two of its rigs. At June 30, 2014, Bison was providing drilling services to the Company using one of its rigs. This master drilling agreement is terminable by either party on 30 days’ prior written notice, although neither party will be relieved of its respective obligations arising from a drilling contract being performed prior to the termination of the master drilling agreement. For the three months and six months ended June 30, 2014, the Company incurred total costs for services performed by Bison of $985,000 and $2,495,000, respectively. For the three months and six months ended June 30, 2013, the Company incurred total costs for services performed by Bison of $4,659,000 and $9,627,000, respectively. The Company owed Bison $56,000 as of June 30, 2014 and no amounts as of December 31, 2013.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC ("Panther Drilling"), an entity controlled by Wexford, Panther Drilling provides directional drilling and other services. This master service agreement is terminable by either party on 30 days' prior written notice, although neither party will be relieved of its respective obligations arising from work performed prior to the termination of the master service agreement. In the third quarter 2013, the Company began using Panther Drilling's directional drilling services. For the three months and six months ended June 30, 2014, the Company incurred total costs for services performed by Panther Drilling of $57,000 and $305,000, respectively. The Company owed Panther Drilling $11,000 as of June 30, 2014 and no amounts as of December 31, 2013.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC ("Coronado Midstream"), formerly known as MidMar Gas LLC, an entity affiliated with Wexford that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream, all of the gas conforming to certain quality specifications produced from certain of the Company's Permian Basin acreage. Following the expiration of the initial ten year term, the agreement will continue on a year-to-year basis until terminated by either party on 30 days' written notice. Under the gas purchase agreement, Coronado Midstream is obligated to pay the Company 87% of the net revenue received by Coronado Midstream for all components of the Company's dedicated gas, including the liquid hydrocarbons, and the sale of residue gas, in each case extracted, recovered or otherwise processed at Coronado Midstream's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron's Headlee plant. The Company recognized revenues from Coronado Midstream of $6,505,000 and $10,412,000 for the three months and six months ended June 30, 2014, respectively, and $1,723,000 and $2,818,000 for the three months and six months ended June 30, 2013, respectively. As of June 30, 2014 and December 31, 2013, Coronado Midstream owed the Company $3,310,000 and $1,303,000, respectively, for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Sand Supply

Muskie Proppant LLC ("Muskie"), an entity affiliated with Wexford, processes and sells fracing grade sand for oil and natural gas operations. The Company began purchasing sand from Muskie in March 2013. On May 16, 2013, the Company entered into a master services agreement with Muskie, pursuant to which Muskie agreed to sell custom natural sand proppant to the Company based on the Company's requirements. The Company is not obligated to place any orders with, or accept any offers from, Muskie for sand proppant. The agreement may be terminated at the option of either party on 30 days' notice. The Company incurred no costs for sand purchased from Muskie for the three months and six months ended June 30, 2014, respectively. The Company incurred no costs and costs of $234,000 for sand purchased from Muskie for the three months and six months ended June 30, 2013, respectively. The Company owed Muskie no amounts as of June 30, 2014 or December 31, 2013.

Midland Leases

Effective May 15, 2011, the Company occupied corporate office space in Midland, Texas under a lease with a five-year term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $98,000 and $191,000 for the three months and six months ended June 30, 2014, respectively, and $43,000 and $82,000, for the three months and six months ended June 30, 2013, respectively, under this lease. In the second and third quarters of 2013, the Company amended this agreement to increase the size of the leased premises. The monthly rent under the lease increased from $13,000 to $15,000 beginning on August 1, 2013 and increased further to $25,000 beginning on October 1, 2013. The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

The Company leased field office space in Midland, Texas from an unrelated third party from March 1, 2011 to March 1, 2014. Effective March 1, 2014, the building was purchased by an entity controlled by an affiliate of Wexford. The remaining term of the lease as of March 1, 2014 is four years. The Company paid rent of $36,000 and $47,000 to the related party for the three months and six months ended June 30, 2014. The monthly base rent is $11,000 which will increase 3% annually on March 1 of each year during the remainder of the lease term.

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Oklahoma City Lease

Effective January 1, 2012, the Company occupied corporate office space in Oklahoma City, Oklahoma under a lease with a 67 month term. The office space is owned by an entity controlled by an affiliate of Wexford. The Company paid $62,000 and $126,000 for the three months and six months ended June 30, 2014, respectively, and $58,000 and $111,000 for the three months and six months ended June 30, 2013, respectively, under this lease. Effective April 1, 2013, the Company amended this lease to increase the size of the leased premises, at which time the monthly base rent increased to $19,000 for the remainder of the lease term. The Company is also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises.

Advisory Services Agreement & Professional Services from Wexford

The Company entered into an advisory services agreement (the “Advisory Services Agreement”) with Wexford, dated as of October 11, 2012, under which Wexford provides the Company with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Advisory Services Agreement has a term of two years commencing on October 18, 2012, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Company terminates such agreement, it is obligated to pay all amounts due through the remaining term. In addition, the Company agreed to pay Wexford to-be-negotiated market-based fees approved by the Company’s independent directors for such services as may be provided by Wexford at the Company’s request in connection with future acquisitions and divestitures, financings or other transactions in which the Company may be involved. The services provided by Wexford under the Advisory Services Agreement do not extend to the Company’s day-to-day business or operations. The Company has agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct. The Company incurred total costs of $125,000 and $250,000 for the three months and six months ended June 30, 2014, respectively, and $125,000 and $250,000 for the three months and six months ended June 30, 2013, respectively, under the Advisory Services Agreement. As of June 30, 2014 and December 31, 2013, the Company owed Wexford no amounts for either period.

Advisory Services Agreement- Viper Energy Partners LP

In connection with the closing of the Viper Offering, the Partnership and General Partner entered into an advisory services agreement (the “Viper Advisory Services Agreement”) with Wexford, dated as of June 23, 2014, under which Wexford provides the Partnership and our General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $500,000, plus reasonable out-of-pocket expenses. The Viper Advisory Services Agreement has a term of two years commencing on June 23, 2014, and will continue for additional one-year periods unless terminated in writing by either party at least ten days prior to the expiration of the then current term. It may be terminated at any time by either party upon 30 days prior written notice. In the event the Partnership or General Partner terminates such agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership and General Partner have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of our General Partner for such services as may be provided by Wexford at our request in connection with future acquisitions and divestitures, financings or other transactions in which we may be involved. The services provided by Wexford under the Viper Advisory Services Agreement do not extend to the Partnership or General Partners day-to-day business or operations. The Partnership and General Partner have agreed to indemnify Wexford and its affiliates from any and all losses arising out of or in connection with the Viper Advisory Services Agreement except for losses resulting from Wexford’s or its affiliates’ gross negligence or willful misconduct.

Secondary Offering Costs

On June 27, 2014, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 2,000,000 shares of the Company's common stock. The shares were sold to the public at $90.04 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred estimated costs of approximately $40,000 related to this secondary public offering.

On June 24, 2013, Gulfport and certain entities controlled by Wexford completed an underwritten secondary public offering of 6,000,000 shares of the Company's common stock and, on July 5, 2013, the underwriters purchased an additional 869,222 shares of the Company's common stock from these selling stockholders pursuant to an option to purchase such additional shares granted to the underwriters. The shares were sold to the public at $34.75 per share and the selling stockholders received all proceeds from this offering after deducting the underwriting discount. The Company incurred costs of approximately $185,000 related to this secondary public offering.

11. DERIVATIVES

All derivative financial instruments are recorded at fair value. The Company has not designated its derivative instruments as hedges for accounting purposes and, as a result, marks its derivative instruments to fair value and recognizes the cash and non-cash changes in fair value in the consolidated statements of operations under the caption "Gain (loss) on derivative instruments, net."

The Company has used price swap contracts to reduce price volatility associated with certain of its oil sales. With respect to the Company's fixed price swap contracts, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is less than the swap price, and the Company is required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. The Company's derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Argus Louisiana light sweet pricing.

By using derivative instruments to hedge exposure to changes in commodity prices, the Company exposes itself to credit risk and market risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty owes the Company, which creates credit risk. The Company's counterparties are participants in the secured second amended and restated credit agreement, which is secured by substantially all of the assets of the guarantor subsidiaries; therefore, the Company is not required to post any collateral. The Company does not require collateral from its counterparties. The Company has entered into derivative instruments only with counterparties that are also lenders in our credit facility and have been deemed an acceptable credit risk.

As of June 30, 2014, the Company had open crude oil derivative positions with respect to future production as set forth in the tables below. When aggregating multiple contracts, the weighted average contract price is disclosed.

Crude Oil—Argus Louisiana Light Sweet Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
July - December 2014	1,288,000	$ 98.64
January - April 2015	331,000	99.71

Balance sheet offsetting of derivative assets and liabilities

The fair value of swaps is generally determined using established index prices and other sources which are based upon, among other things, futures prices and time to maturity. These fair values are recorded by netting asset and liability positions that are with the same counterparty and are subject to contractual terms which provide for net settlement.

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under master netting arrangements with counterparties and the resulting net amounts presented in the Company's consolidated balance sheets as of June 30, 2014 and December 31, 2013.

	June 30, 2014 (in thousands)		
	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Liabilities Presented in the Consolidated Balance Sheet
Derivative liabilities	$ (10,379)	$ —	$ (10,379)

	December 31, 2013 (in thousands)		
	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheet	Net Amounts of Assets Presented in the Consolidated Balance Sheet
Derivative assets	$ 998	$ (567)	$ 431

The net amounts are classified as current or noncurrent based on their anticipated settlement dates. The net fair value of the Company's derivative assets and liabilities and their locations on the consolidated balance sheet are as follows:

	June 30, 2014	December 31, 2013
	(in thousands)	
Current Assets: Derivative instruments	$ —	$ 213
Noncurrent Assets: Derivative instruments	—	218
Total Assets	$ —	$ 431
Current Liabilities: Derivative instruments	$ (10,379)	$ —
Noncurrent Liabilities: Derivative instruments	—	—
Total Liabilities	$ (10,379)	$ —

None of the Company's derivatives have been designated as hedges. As such, all changes in fair value are immediately recognized in earnings. The following table summarizes the gains and losses on derivative instruments included in the consolidated statements of operations:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Non-cash gain (loss) on open non-hedge derivative instruments	$ (7,468)	$ 3,893	$ (10,810)	$ 5,428
Loss on settlement of non-hedge derivative instruments	(3,620)	(856)	(4,676)	(2,399)
Gain (loss) on derivative instruments	$ (11,088)	$ 3,037	$ (15,486)	$ 3,029

12. FAIR VALUE MEASUREMENTS

Fair value is defined as 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. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs.

The fair value hierarchy is based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value. The Company's assessment of the significance of a particular input to the fair value measurements requires judgment and may affect the valuation of the assets and liabilities being measured and their placement within the fair value hierarchy. The Company uses appropriate valuation techniques based on available inputs to measure the fair values of its assets and liabilities.

Level 1 - Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.

Level 2 - Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date.

Level 3 - Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Certain assets and liabilities are reported at fair value on a recurring basis, including the Company's derivative instruments. The fair values of the Company's fixed price crude oil swaps are measured internally using established commodity futures price strips for the underlying commodity provided by a reputable third party, the contracted notional volumes, and time to maturity. These valuations are Level 2 inputs.

The following table provides fair value measurement information for financial assets and liabilities measured at fair value on a recurring basis as of June 30, 2014 and December 31, 2013.

	Fair value measurements at June 30, 2014 using: (in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Liabilities:				
Fixed price swaps	—	(10,379)	—	(10,379)

	Fair value measurements at December 31, 2013 using: (in thousands)			
	Quoted Prices in Active Markets Level 1	Significant Other Observable Inputs Level 2	Significant Unobservable Inputs Level 3	Total
Assets:				
Fixed price swaps	$ —	$ 431	$ —	$ 431

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated financial statements.

	June 30, 2014		December 31, 2013	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$ 46,000	$ 46,000	$ 10,000	$ 10,000
7.625% Senior Notes due 2021	450,000	497,250	450,000	460,406

The fair value of the revolving credit facility approximates its carrying value based on borrowing rates available to the Company for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy. The fair value of the Senior Notes was determined using the June 30, 2014 quoted market price, a Level 1 classification in the fair value hierarchy.

13. CONTINGENCIES

In September 2010, Windsor Permian LLC (“Windsor Permian”) (now known as Diamondback O&G LLC) purchased certain property in Goodhue County, Minnesota, that was prospective for hydraulic fracturing grade sand. Prior to the purchase, the prior owners of the property had entered into a Mineral Development Agreement with the plaintiff and the Company purchased the property subject to that agreement. Windsor Permian subsequently contributed the property to Muskie. In an amended complaint filed in November 2012 by the plaintiff against the prior owners of the property, Windsor Permian and certain affiliates of Windsor Permian in the first judicial district court in Goodhue County, Minnesota, the plaintiff sought damages from the Company and the other defendants alleging, among other things, interference with contractual relationship, interference with prospective advantage and unjust enrichment. In an order filed on May 24, 2013, the judge denied certain motions made by the defendants and set a trial date to determine liability, with a damage phase of the matter to commence on a later date if there is a determination of liability. Following a trial on the liability phase on June 21, 2013, the jury determined that the defendants intentionally interfered with plaintiff’s contract but that the interference did not cause the plaintiff to be unable to acquire mining permits prior to the enactment of the moratorium by Goodhue County. In an order filed on July 10, 2013, the judge ordered the damage phase to be set for trial following a pretrial and scheduling conference. Subsequently, the plaintiff disclosed a new damage theory, and the defendants filed motions with the court to dismiss plaintiff’s claims on the grounds that the damage claim was speculative and that plaintiff could not prove damages as a matter of law. Plaintiff also filed a motion for leave to amend its complaint to assert a punitive damage claim. The motions were argued in December 2013. In March 2014, the judge entered an order granting the defendants’ motions to exclude testimony and for summary judgment. All parties agreed not to pursue an appeal from the order and waived any entitlement to costs, which effectively concluded this matter.

The Company could be subject to various possible loss contingencies which arise primarily from interpretation of federal and state laws and regulations affecting the natural gas and crude oil industry. Such contingencies include differing interpretations as to the prices at which natural gas and crude oil sales may be made, the prices at which royalty owners may be paid for production from their leases, environmental issues and other matters. Management believes it has complied with the various laws and regulations, administrative rulings and interpretations.

14. SUBSEQUENT EVENTS

The Company entered into a definitive purchase agreement dated July 18, 2014 with unrelated third party sellers to acquire additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas in the Permian Basin, for an aggregate purchase price of approximately $538.0 million, subject to certain adjustments. This transaction includes 16,773 gross (13,136 net) acres with a 78% working interest (approximately 75.1% net revenue interest). The proposed transaction is scheduled to close in early September 2014.

On July 25, 2014, the Company completed an underwritten public offering of 5,750,000 shares of common stock, which included 750,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the public at $87.00 per share and the Company received net proceeds of approximately $484.9 million from the sale of these shares of common stock, net of the underwriting discount and estimated offering expenses. The net proceeds from this offering will be used to partially fund the acquisition described above. To the extent the pending acquisition is not consummated, or the actual purchase price is less than the net proceeds from the offering, the Company intends to use the net proceeds from the offering to fund a portion of its exploration and development activities and for general corporate purposes, which may include leasehold interest and property acquisitions and working capital.

On July 25, 2014, the Company repaid all outstanding amounts under its credit agreement with Wells Fargo with a portion of the proceeds from its equity offering, pending reborrowing to fund a portion of the purchase price of the acquisition described above.

On July 8, 2014, the Partnership entered into a secured revolving credit agreement with Wells Fargo, as the administrative agent, sole book runner and lead arranger. The Partnership had outstanding borrowings of $50.0 million as of August 6, 2014. See Note—7 Debt for additional information.

15. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P and Diamondback O&G are unconditional guarantor's (the "Guarantor Subsidiaries") of the Senior Notes and the second amended and restated credit agreement. On June 23, 2014, in connection with the initial public offering of Viper Energy Partners LP the Company designated the Partnership, its general partner, Viper Energy Partners GP, and the Partnership's subsidiary Viper Energy Partners LLC as unrestricted subsidiaries under the Indenture and upon such designation, Viper Energy Partners LLC, which was a guarantor under the Indenture prior to such designation, was released as a guarantor under the Indenture. Viper Energy Partners LLC is a limited liability company formed on September 18, 2013 to own and acquire mineral and other oil and natural gas interests in properties in the Permian Basin in West Texas. The following presents condensed consolidated financial information as of December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 on an issuer (parent company), Guarantor Subsidiaries, Non–Guarantor Subsidiaries and consolidated basis. Elimination entries presented are necessary to combine the entities. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantor Subsidiaries operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantor Subsidiaries because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantor Subsidiaries.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
June 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 7,504	$ 22,460	$ 7,029	$ —	$ 36,993
Accounts receivable	—	58,177	7,168	—	65,345
Accounts receivable - related party	—	3,310	—	—	3,310
Intercompany receivable	1,139,057	1,142,456	—	(2,281,513)	—
Inventories	—	3,308	—	—	3,308
Deferred income taxes	4,327	—	—	—	4,327
Other current assets	131	1,274	16	—	1,421
Total current assets	1,151,019	1,230,985	14,213	(2,281,513)	114,704
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	1,738,012	453,309	—	2,191,321
Pipeline and gas gathering assets	—	6,846	—	—	6,846
Other property and equipment	—	4,973	—	—	4,973
Accumulated depletion, depreciation, amortization and impairment	—	(268,115)	(16,830)	1,793	(283,152)
	—	1,481,716	436,479	1,793	1,919,988
Investment in subsidiaries	613,000	—	—	(613,000)	—
Other assets	9,750	2,952	—	—	12,702
Total assets	$ 1,773,769	$ 2,715,653	$ 450,692	$ (2,892,720)	$ 2,047,394
Liabilities and Stockholders’ Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 22,755	$ 720	$ —	$ 23,475
Accounts payable-related party	—	67	—	—	67
Intercompany payable	75,450	2,194,196	11,867	(2,281,513)	—
Other current liabilities	8,675	135,226	1,434	—	145,335
Total current liabilities	84,125	2,352,244	14,021	(2,281,513)	168,877
Long-term debt	450,000	46,000	—	—	496,000
Asset retirement obligations	—	5,437	—	—	5,437
Deferred income taxes	124,743	—	—	—	124,743
Total liabilities	658,868	2,403,681	14,021	(2,281,513)	795,057
Commitments and contingencies					
Stockholders’ equity:	1,114,901	311,972	436,671	(748,643)	1,114,901
Noncontrolling interest	—	—	—	137,436	137,436
Total equity	1,114,901	311,972	436,671	(611,207)	1,252,337
Total liabilities and equity	$ 1,773,769	$ 2,715,653	$ 450,692	$ (2,892,720)	$ 2,047,394

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Balance Sheet
December 31, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 526	$ 14,267	$ 762	$ —	$ 15,555
Accounts receivable	—	28,544	—	9,426	37,970
Accounts receivable - related party	—	1,303	—	—	1,303
Royalty income receivable	—	—	9,426	(9,426)	—
Intercompany receivable	715,169	413,744	—	(1,128,913)	—
Intercompany note receivable	440,000	—	—	(440,000)	—
Inventories	—	5,631	—	—	5,631
Deferred income taxes	112	—	—	—	112
Other current assets	—	1,397	—	—	1,397
Total current assets	1,155,807	464,886	10,188	(1,568,913)	61,968
Property and equipment					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	1,200,326	448,034	—	1,648,360
Pipeline and gas gathering assets	—	6,142	—	—	6,142
Other property and equipment	—	4,071	—	—	4,071
Accumulated depletion, depreciation, amortization and impairment	—	(207,037)	(5,199)	—	(212,236)
	—	1,003,502	442,835	—	1,446,337
Investment in subsidiaries	235,334	—	—	(235,334)	—
Other assets	10,207	3,102	—	—	13,309
Total assets	$ 1,401,348	$ 1,471,490	$ 453,023	$ (1,804,247)	$ 1,521,614
Liabilities and Stockholders' Equity					
Current liabilities:					
Accounts payable-trade	$ —	$ 2,679	$ —	$ —	$ 2,679
Accounts payable-related party	—	17	—	—	17
Intercompany payable	3,920	1,115,214	87	(1,119,221)	—
Intercompany accrued interest	—	—	9,692	(9,692)	—
Other current liabilities	10,123	108,245	256	—	118,624
Total current liabilities	14,043	1,226,155	10,035	(1,128,913)	121,320
Long-term debt	450,000	10,000	—	—	460,000
Intercompany note payable	—	—	440,000	(440,000)	—
Asset retirement obligations	—	2,989	—	—	2,989
Deferred income taxes	91,764	—	—	—	91,764
Total liabilities	555,807	1,239,144	450,035	(1,568,913)	676,073
Commitments and contingencies					
Stockholders' equity:	845,541	232,346	2,988	(235,334)	845,541
Total equity	845,541	232,346	2,988	(235,334)	845,541
Total liabilities and equity	$ 1,401,348	$ 1,471,490	$ 453,023	$ (1,804,247)	$ 1,521,614

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended June 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 99,573	$ —	$ 15,709	$ 115,282
Natural gas sales	—	3,738	—	591	4,329
Natural gas liquid sales	—	6,444	—	949	7,393
Royalty income	—	—	17,249	(17,249)	—
Total revenues	—	109,755	17,249	—	127,004
Costs and expenses:					
Lease operating expenses	—	10,496	—	—	10,496
Production and ad valorem taxes	—	7,162	1,392	—	8,554
Gathering and transportation	—	703	—	—	703
Depreciation, depletion and amortization	—	34,616	5,405	—	40,021
General and administrative expenses	3,428	287	219	—	3,934
Asset retirement obligation accretion expense	—	104	—	—	104
Intercompany charges	—	—	78	—	—
Total costs and expenses	3,428	53,368	7,094	—	63,812
Income (loss) from operations	(3,428)	56,387	10,155	—	63,192
Other income (expense)					
Interest income - intercompany	5,387	—	—	(5,387)	—
Interest expense	(6,657)	(1,082)	—	—	(7,739)
Interest expense - intercompany	—	—	(5,387)	5,387	—
Other income - related party	—	108	—	(78)	30
Other expense	—	(1,408)	—	—	(1,408)
Gain (loss) on derivative instruments, net	—	(11,088)	—	—	(11,088)
Total other income (expense), net	(1,270)	(13,470)	(5,387)	(78)	(20,205)
Income (loss) before income taxes	(4,698)	42,917	4,768	(78)	42,987
Provision for income taxes	15,163	—	—	—	15,163
Net income (loss)	(19,861)	42,917	4,768	(78)	27,824
Less: Net income attributable to noncontrolling interest	—	—	—	71	71
Net income (loss) attributable to Diamondback Energy, Inc.	$ (19,861)	$ 42,917	$ 4,768	$ (149)	$ 27,753

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Three Months Ended June 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 41,034	$ —	$ —	$ 41,034
Natural gas sales	—	1,668	—	—	1,668
Natural gas liquid sales	—	2,692	—	—	2,692
Total revenues	—	45,394	—	—	45,394
Costs and expenses:					
Lease operating expenses	—	4,968	—	—	4,968
Production and ad valorem taxes	—	3,315	—	—	3,315
Gathering and transportation	—	247	—	—	247
Depreciation, depletion and amortization	—	14,815	—	—	14,815
General and administrative expenses	955	1,666	—	—	2,621
Asset retirement obligation accretion expense	—	45	—	—	45
Total costs and expenses	955	25,056	—	—	26,011
Income (loss) from operations	(955)	20,338	—	—	19,383
Other income (expense)					
Interest expense	—	(535)	—	—	(535)
Other income - related party	—	388	—	—	388
Gain on derivative instruments, net	—	3,037	—	—	3,037
Total other income (expense), net	—	2,890	—	—	2,890
Income (loss) before income taxes	(955)	23,228	—	—	22,273
Provision for income taxes	7,802	—	—	—	7,802
Net income (loss)	$ (8,757)	$ 23,228	$ —	$ —	$ 14,471

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Six Months Ended June 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 176,868	$ —	$ 30,671	$ 207,539
Natural gas sales	—	8,168	—	1,169	9,337
Natural gas liquid sales	—	6,416	—	1,716	8,132
Royalty income	—	—	33,102	(33,102)	—
Total revenues	—	191,452	33,102	454	225,008
Costs and expenses:					
Lease operating expenses	—	18,411	—	—	18,411
Production and ad valorem taxes	—	12,065	2,331	—	14,396
Gathering and transportation	—	1,285	—	—	1,285
Depreciation, depletion and amortization	—	60,417	10,577	—	70,994
General and administrative expenses	7,413	793	285	—	8,491
Asset retirement obligation accretion expense	—	176	—	—	176
Intercompany charges	—	—	156	(156)	—
Total costs and expenses	7,413	93,147	13,349	(156)	113,753
Income (loss) from operations	(7,413)	98,305	19,753	610	111,255
Other income (expense)					
Interest income - intercompany	10,755	—	—	(10,755)	—
Interest expense	(12,544)	(1,700)	—	—	(14,244)
Interest expense - intercompany	—	—	(10,755)	10,755	—
Other income - related party	—	216	—	(156)	60
Other expense	—	(1,408)	—	—	(1,408)
Gain (loss) on derivative instruments, net	—	(15,486)	—	—	(15,486)
Total other income (expense), net	(1,789)	(18,378)	(10,755)	(156)	(31,078)
Income (loss) before income taxes	(9,202)	114,519	7,962	(33,102)	80,177
Provision for income taxes	28,764	—	—	—	28,764
Net income (loss)	(37,966)	114,519	7,962	(33,102)	51,413
Less: Net income attributable to noncontrolling interest	—	—	—	71	71
Net income (loss) attributable to Diamondback Energy, Inc.	$ (37,966)	$ 114,519	$ 7,962	$ (33,173)	$ 51,342

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Operations
Six Months Ended June 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil sales	$ —	$ 66,287	$ —	$ —	$ 66,287
Natural gas sales	—	2,819	—	—	2,819
Natural gas liquid sales	—	5,197	—	—	5,197
Total revenues	—	74,303	—	—	74,303
Costs and expenses:					
Lease operating expenses	—	10,403	—	—	10,403
Production and ad valorem taxes	—	4,742	—	—	4,742
Gathering and transportation	—	380	—	—	380
Depreciation, depletion and amortization	—	25,553	—	—	25,553
General and administrative expenses	1,696	3,396	—	—	5,092
Asset retirement obligation accretion expense	—	88	—	—	88
Total costs and expenses	1,696	44,562	—	—	46,258
Income (loss) from operations	(1,696)	29,741	—	—	28,045
Other income (expense)					
Interest expense	—	(1,020)	—	—	(1,020)
Other income - related party	—	777	—	—	777
Gain (loss) on derivative instruments, net	—	3,029	—	—	3,029
Total other income (expense), net	—	2,786	—	—	2,786
Income (loss) before income taxes	(1,696)	32,527	—	—	30,831
Provision for income taxes	10,964	—	—	—	10,964
Net income (loss)	$ (12,660)	$ 32,527	$ —	$ —	$ 19,867

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Six Months Ended June 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ (2,145)	$ 138,172	$ 14,064	$ 9,615	$ 159,706
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(204,075)	(5,275)	—	(209,350)
Acquisition of leasehold interests	—	(312,207)	—	—	(312,207)
Intercompany transfers	(203,169)	223,169	—	(20,000)	—
Other investing activities	—	(2,088)	—	—	(2,088)
Net cash used in investing activities	(203,169)	(295,201)	(5,275)	(20,000)	(523,645)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	166,000	—	—	166,000
Repayment on credit facility	—	(130,000)	—	—	(130,000)
Proceeds from public offerings	208,644	—	139,035	—	347,679
Distribution to parent	—	—	(137,500)	137,500	—
Intercompany transfers	—	130,000	—	(130,000)	—
Other financing activities	3,648	(778)	(4,057)	2,885	1,698
Net cash provided by (used in) financing activities	212,292	165,222	(2,522)	10,385	385,377
Net increase in cash and cash equivalents	6,978	8,193	6,267	—	21,438
Cash and cash equivalents at beginning of period	526	14,267	762	—	15,555
Cash and cash equivalents at end of period	$ 7,504	$ 22,460	$ 7,029	$ —	$ 36,993

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
(Unaudited)

Condensed Consolidated Statement of Cash Flows
Six Months Ended June 30, 2013
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$ 6	$ 49,792	$ —	$ —	$ 49,798
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(112,083)	—	—	(112,083)
Acquisition of leasehold interests	—	(24,742)	—	—	(24,742)
Intercompany transfers	(20,132)	20,132	—	—	—
Other investing activities	—	(1,850)	—	—	(1,850)
Net cash used in investing activities	(20,132)	(118,543)	—	—	(138,675)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	49,000	—	—	49,000
Repayment on credit facility	—	(49,000)	—	—	(49,000)
Proceeds from public offerings	144,936	—	—	—	144,936
Distribution to parent	—	—	—	—	—
Intercompany transfers	(49,000)	49,000	—	—	—
Other financing activities	(447)	(72)	—	—	(519)
Net cash provided by (used in) financing activities	95,489	48,928	—	—	144,417
Net increase in cash and cash equivalents	75,363	(19,823)	—	—	55,540
Cash and cash equivalents at beginning of period	14	26,344	—	—	26,358
Cash and cash equivalents at end of period	$ 75,377	$ 6,521	$ —	$ —	$ 81,898