Diamondback Energy, Inc.
Form 10-Q
November 06, 2015

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

FORM 10-Q

ý QUARTERLY REPORT UNDER SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2015
OR
o TRANSITION REPORT UNDER SECTION 13 OR 15(d) OF SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-35700

Diamondback Energy, Inc.
(Exact Name of Registrant As Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	45-4502447 (IRS Employer Identification Number)
500 West Texas, Suite 1200 Midland, Texas	79701
(Address of Principal Executive Offices)	(Zip Code)

(432) 221-7400
(Registrant Telephone Number, Including Area Code)

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

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

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

Large Accelerated Filer	ý	Accelerated Filer	o

Non-Accelerated Filer	o	Smaller Reporting Company	o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No ý
As of November 3, 2015, 66,703,004 shares of the registrant’s common stock were outstanding.

DIAMONDBACK ENERGY, INC
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2015
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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a glossary of certain oil and gas terms that are used in this Quarterly Report on Form 10-Q (this "report"):

3-D seismic	Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.
Basin	A large depression on the earth's surface in which sediments accumulate.
Bbl	Stock tank barrel, or 42 U.S. gallons liquid volume, used in this report in reference to crude oil or other liquid hydrocarbons.
Bbls/d	Bbls per day.
BOE	Barrels of oil equivalent, with six thousand cubic feet of natural gas being equivalent to one barrel of oil.
BOE/d	BOE per day.
Completion	The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
Condensate	Liquid hydrocarbons associated with the production of a primarily natural gas reserve.
Crude oil	Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.
Finding and development costs	Capital costs incurred in the acquisition, exploitation and exploration of proved oil and natural gas reserves divided by proved reserve additions and revisions to proved reserves.
Gross acres or gross wells	The total acres or wells, as the case may be, in which a working interest is owned.
Horizontal drilling	A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle with a specified interval.
Horizontal wells	Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.
MBOE	One thousand barrels of crude oil equivalent, determined using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.
Mcf	Thousand cubic feet of natural gas.
Mcf/d	Mcf per day.
Mineral interests	The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.
MMBtu	Million British Thermal Units.
Net acres or net wells	The sum of the fractional working interest owned in gross acres.
Net revenue interest	An owner's interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.
Oil and natural gas properties	Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.
Operator	The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.
Play	A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.
Plugging and abandonment	Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.
Prospect	

	A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is deemed to have potential for the discovery of commercial hydrocarbons.
Proved reserves	The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

Reserves	Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to the market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Royalty interest	An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development.
Spacing	The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 40-acre spacing) and is often established by regulatory agencies.
Working interest	An operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production and requires the owner to pay a share of the costs of drilling and production operations.

GLOSSARY OF CERTAIN OTHER TERMS

The following is a glossary of certain other terms that are used in this report.

2012 Plan	The Company's 2012 Equity Incentive Plan.
Company	Diamondback Energy, Inc., a Delaware corporation.
Exchange Act	The Securities Exchange Act of 1934, as amended.
GAAP	Accounting principles generally accepted in the United States.
General Partner	Viper Energy Partners GP LLC, a Delaware limited liability company and the General Partner of the Partnership.
Indenture	The indenture relating to the Senior Notes, dated as of September 18, 2013, among the Company, the subsidiary guarantors party thereto and Wells Fargo, as the trustee, as supplemented.
NYMEX	New York Mercantile Exchange.
Partnership	Viper Energy Partners LP, a Delaware limited partnership.
Partnership agreement	The first amended and restated agreement of limited partnership, dated June 23, 2014, entered into by the General Partner and Diamondback in connection with the closing of the Viper Offering.
SEC	Securities and Exchange Commission.
Securities Act	The Securities Act of 1933, as amended.
Senior Notes	The Company's 7.625% senior unsecured notes due 2021 in the aggregate principal amount of $450 million.
Viper LTIP	Viper Energy Partners LP Long Term Incentive Plan.
Viper Offering	The Partnerships' initial public offering.
Wells Fargo	Wells Fargo Bank, National Association.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act, and Section 21E of the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this report and detailed under Part II, Item 1A. Risk Factors in this report and our Annual Report on Form 10–K for the year ended December 31, 2014 could affect our actual results and cause our actual results to differ materially from expectations, estimates or assumptions expressed, forecasted or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- exploration and development drilling prospects, inventories, projects and programs;
- oil and natural gas reserves;
- acquisitions;
- identified drilling locations;
- ability to obtain permits and governmental approvals;
- technology;
- financial strategy;
- realized oil and natural gas prices;
- production;
- lease operating expenses, general and administrative costs and finding and development costs;
- future operating results; and
- plans, objectives, expectations and intentions.

All forward-looking statements speak only as of the date of this report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

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

	September 30, 2015	December 31, 2014
	(In thousands, except par values and share data)	
Assets		
Current assets:		
Cash and cash equivalents	$43,827	$30,183
Restricted cash	500	500
Accounts receivable:		
Joint interest and other	41,021	50,943
Oil and natural gas sales	42,221	43,050
Related party	—	4,001
Inventories	2,602	2,827
Derivative instruments	40,009	115,607
Prepaid expenses and other	3,259	4,600
Total current assets	173,439	251,711
Property and equipment:		
Oil and natural gas properties, based on the full cost method of accounting ($1,099,604 and $773,520 excluded from amortization at September 30, 2015 and December 31, 2014, respectively)	3,850,064	3,118,597
Pipeline and gas gathering assets	7,176	7,174
Other property and equipment	48,913	48,180
Accumulated depletion, depreciation, amortization and impairment	(1,147,936)	(382,144)
Net property and equipment	2,758,217	2,791,807
Derivative instruments	—	1,934
Deferred income taxes	5,641	—
Other assets	54,257	50,029
Total assets	$2,991,554	$3,095,481
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable-trade	$32,010	$26,230
Accrued capital expenditures	58,818	129,397
Other accrued liabilities	76,527	41,149
Revenues and royalties payable	20,421	30,000
Deferred income taxes	12,396	39,953
Total current liabilities	200,172	266,729
Long-term debt	489,000	673,500
Asset retirement obligations	12,662	8,447
Deferred income taxes	—	161,592
Total liabilities	701,834	1,110,268
Commitments and contingencies (Note 14)		
Stockholders' equity:		
	667	569

Common stock, $0.01 par value, 100,000,000 shares authorized, 66,656,433 issued and outstanding at September 30, 2015; 56,887,583 issued and outstanding at December 31, 2014		
Additional paid-in capital	2,222,695	1,554,174
Retained earnings	(166,951)	196,268
Total Diamondback Energy, Inc. stockholders' equity	2,056,411	1,751,011
Noncontrolling interest	233,309	234,202
Total equity	2,289,720	1,985,213
Total liabilities and equity	$2,991,554	$3,095,481

See accompanying notes to combined consolidated financial statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share amounts)			
Revenues:				
Oil sales	$101,307	$126,406	$301,850	$331,446
Natural gas sales	5,673	2,338	11,791	6,006
Natural gas sales - related party	—	2,374	2,640	6,370
Natural gas liquid sales	4,966	3,619	13,585	9,507
Natural gas liquid sales - related party	—	4,390	2,544	10,806
Total revenues	111,946	139,127	332,410	364,135
Costs and expenses:				
Lease operating expenses	22,189	13,766	65,117	31,998
Lease operating expenses - related party	—	39	—	218
Production and ad valorem taxes	8,966	8,634	24,883	22,318
Production and ad valorem taxes - related party	—	320	153	1,032
Gathering and transportation	1,688	110	3,374	426
Gathering and transportation - related party	—	750	969	1,719
Depreciation, depletion and amortization	52,375	45,370	169,148	116,364
Impairment of oil and gas properties	273,737	—	597,188	—
General and administrative expenses (including non-cash equity based compensation, net of capitalized amounts, of $4,402 and $2,069 for the three months ended September 30, 2015 and 2014, respectively, and $13,659 and $5,387 for the nine months ended September 30, 2015 and 2014, respectively)	6,861	6,016	21,774	13,891
General and administrative expenses - related party	665	479	1,672	1,095
Asset retirement obligation accretion expense	238	127	588	303
Total costs and expenses	366,719	75,611	884,866	189,364
Income (loss) from operations	(254,773)	63,516	(552,456)	174,771
Other income (expense)				
Interest expense	(10,633)	(9,846)	(31,404)	(24,090)
Other income	260	17	1,130	17
Other income - related party	40	31	118	91
Other expense	—	(8)	—	(1,416)
Gain (loss) on derivative instruments, net	27,603	14,909	26,834	(577)
Total other income (expense), net	17,270	5,103	(3,322)	(25,975)
Income (loss) before income taxes	(237,503)	68,619	(555,778)	148,796
Provision for (benefit from) income taxes	(81,461)	23,978	(194,823)	52,742
Net income (loss)	(156,042)	44,641	(360,955)	96,054
Less: Net income attributable to noncontrolling interest	739	902	2,264	973
Net income (loss) attributable to Diamondback Energy, Inc.	$(156,781)	$43,739	$(363,219)	$95,081

Earnings (loss) per common share				
Basic	$(2.40)	$0.79	$(5.88)	$1.85
Diluted	$(2.40)	$0.79	$(5.88)	$1.83
Weighted average common shares outstanding				
Basic	65,251	55,152	61,727	51,489
Diluted	65,251	55,442	61,727	51,888

See accompanying notes to combined consolidated financial statements.

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

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Retained Earnings	Non-controlling 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	—	—	—	—	232,334	232,334
Unit-based compensation	—	—	—	—	1,011	1,011
Stock-based compensation	—	—	9,134	—	—	9,134
Tax benefits related to stock-based compensation	—	—	3,173	—	—	3,173
Common shares issued in public offering, net of offering costs	9,200	92	693,289	—	—	693,381
Exercise of stock options and vesting of restricted stock units	380	4	5,214	—	—	5,218
Net income	—	—	—	95,081	973	96,054
Balance September 30, 2014	56,686	$567	$1,553,367	$97,594	$ 234,318	$1,885,846
Balance December 31, 2014	56,888	$569	$1,554,174	$196,268	$ 234,202	$1,985,213
Unit-based compensation	—	—	—	—	2,956	2,956
Stock-based compensation	—	—	15,827	—	—	15,827
Distribution to noncontrolling interest	—	—	—	—	(6,113)	(6,113)
Common shares issued in public offering, net of offering costs	9,487	94	649,979	—	—	650,073
Exercise of stock options and vesting of restricted stock units	282	4	2,715	—	—	2,719
Net income (loss)	—	—	—	(363,219)	2,264	(360,955)
Balance September 30, 2015	66,657	$667	$2,222,695	$(166,951)	$ 233,309	$2,289,720

See accompanying notes to combined consolidated financial statements.

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

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$(360,955)	$96,054
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
(Benefit from) provision for deferred income taxes	(194,790)	48,760
Excess tax benefit from stock-based compensation	—	749
Impairment of oil and gas properties	597,188	—
Asset retirement obligation accretion expense	588	303
Depreciation, depletion, and amortization	169,148	116,364
Amortization of debt issuance costs	1,918	1,505
Change in fair value of derivative instruments	77,532	(5,630)
Stock-based compensation expense	13,659	5,387
Gain on sale of assets, net	(91)	1,405
Changes in operating assets and liabilities:		
Accounts receivable	13,112	(33,985)
Accounts receivable-related party	—	(2,612)
Inventories	225	915
Prepaid expenses and other	569	(5,681)
Accounts payable and accrued liabilities	22,756	7,812
Accounts payable and accrued liabilities-related party	—	(17)
Accrued interest	8,324	11,940
Revenues and royalties payable	(9,579)	8,726
Net cash provided by operating activities	339,604	251,995
Cash flows from investing activities:		
Additions to oil and natural gas properties	(326,441)	(309,009)
Additions to oil and natural gas properties-related party	(26)	(3,410)
Acquisition of mineral interests	(32,291)	(57,688)
Acquisition of leasehold interests	(425,507)	(840,482)
Pipeline and gas gathering assets	(2)	(1,437)
Purchase of other property and equipment	(992)	(43,215)
Proceeds from sale of property and equipment	97	11
Equity investments	(2,702)	(33,851)
Net cash used in investing activities	(787,864)	(1,289,081)
Cash flows from financing activities:		
Proceeds from borrowings on credit facility	392,501	425,900
Repayment on credit facility	(577,001)	(295,900)
Debt issuance costs	(303)	(2,358)
Public offering costs	(586)	(2,203)
Proceeds from public offerings	650,688	928,432
Exercise of stock options	2,718	5,131
Excess tax benefits of stock-based compensation	—	3,173
Distribution to non-controlling interest	(6,113)	—

Net cash provided by financing activities	461,904	1,062,175
Net increase in cash and cash equivalents	13,644	25,089
Cash and cash equivalents at beginning of period	30,183	15,555
Cash and cash equivalents at end of period	$43,827	$40,644

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

	Nine Months Ended September 30,	
	2015	2014
	(In thousands)	
Supplemental disclosure of cash flow information:		
Interest paid, net of capitalized interest	$21,117	$12,729
Supplemental disclosure of non-cash transactions:		
Asset retirement obligation incurred	$448	$567
Asset retirement obligation revisions in estimated liability	$60	$588
Asset retirement obligation acquired	$3,123	$3,678
Change in accrued capital expenditures	$(70,579)	$43,865
Capitalized stock-based compensation	$5,125	$4,758

See accompanying notes to combined consolidated financial statements.

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 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. 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, and the Company’s common units represented an approximate 92% limited partner interest in the Partnership. On September 19, 2014, the Partnership completed an underwritten public offering of 3,500,000 common units. At the completion of this offering, the Company owned approximately 88% of the common units of the Partnership. See Note 4—Viper Energy Partners LP for additional information regarding the Partnership.

The wholly-owned subsidiaries of Diamondback, as of September 30, 2015, include Diamondback E&P LLC, a Delaware limited liability company, Diamondback O&G LLC, a Delaware limited liability company, Viper Energy Partners GP LLC, a Delaware limited liability company, and White Fang Energy 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.

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 September 30, 2015, the Company owned approximately 88% of the common units of the Partnership and the Company’s wholly-owned subsidiary, Viper Energy Partners GP LLC, is the General Partner of the Partnership.

These financial statements have been prepared by the Company without audit, pursuant to the rules and regulations of 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 GAAP 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, 2014, 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.

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

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.

New Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers". This update supersedes most of the existing revenue recognition requirements in GAAP and requires (i) an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services and (ii) requires expanded disclosures regarding the nature, amount, timing, and certainty of revenue and cash flows from contracts with customers. The standard will be effective for annual and interim reporting periods beginning after December 15, 2017, with early application not permitted. The standard allows for either full retrospective adoption, meaning the standard is applied to all periods presented in the financial statements, or modified retrospective adoption, meaning the standard is applied only to the most current period presented. The Company is currently evaluating the impact, if any, that the adoption of this update will have on the Company's financial position, results of operations, and liquidity.

In April 2015, the Financial Accounting Standards Board issued Accounting Standards Update 2015-03, "Interest—Imputation of Interest". This update requires that debt issuance costs related to a recognized debt liability (except costs associated with revolving debt arrangements) be presented in the balance sheet as a direct deduction from that debt liability, consistent with the presentation of a debt discount to simplify the presentation of debt issuance costs. The standard will be effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within fiscal years beginning after December 15, 2016. Early application will be permitted for financial statements that have not previously been issued. Adoption of the new guidance will only affect the presentation of the Company's consolidated balance sheets and will not have a material impact on its consolidated financial statements.

3. ACQUISITIONS

2015 Activity

Since January 1, 2015, the Company has completed acquisitions from unrelated third party sellers of an aggregate of approximately 16,034 gross (12,396 net) acres in the Midland Basin, primarily in northwest Howard County, for an aggregate purchase price of approximately $425.5 million, subject to certain adjustments. 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 with the net proceeds of the May 2015 equity offering discussed in Note 9 and borrowings under the Company's revolving credit facility discussed in Note 8.

On July 9, 2015, the Company completed the sale of an approximate average 1.5% overriding royalty interest in certain of its acreage primarily located in Howard County, Texas to the Partnership for $31.1 million. The Partnership primarily funded this acquisition with borrowings under its revolving credit facility discussed in Note 8.

2014 Activity

On September 9, 2014, the Company completed the acquisition of oil and natural gas interests in the Permian Basin from unrelated third party sellers. The Company acquired approximately 17,617 gross (12,967 net) acres with an approximate 74% working interest (approximately 75% net revenue interest). The acquisition was accounted for according to the acquisition method, which requires the recording of net assets acquired and consideration transferred at fair value. This acquisition was funded with the net proceeds of the July 2014 equity offering discussed in Note 9 below and borrowings under the Company’s revolving credit facility discussed in Note 8.

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

There were no material changes from the purchase price allocation disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

The Company has included in its consolidated statements of operations revenues of $4.9 million and direct operating expenses of $2.8 million for the three months ended September 30, 2015 due to the acquisition and revenues of $15.9 million and direct operating expenses of $8.4 million for the nine months ended September 30, 2015 due to the acquisition. For each of the three and nine months ended September 30, 2014, the Company has included in its consolidated statements of operations revenues of $2.8 million and direct operating expenses of $1.4 million attributable to the period from September 9, 2014 to September 30, 2014 due to the acquisition. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

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 with the net proceeds of the February 2014 equity offering discussed in Note 9 and borrowings under the Company's revolving credit facility discussed in Note 8.

There were no material changes from the purchase price allocation disclosed in the Company's Annual Report on Form 10-K for the year ended December 31, 2014.

The Company has included in its consolidated statements of operations revenues of $9.8 million and direct operating expenses of $2.7 million for the three months ended September 30, 2015 and revenues of $11.8 million and direct operating expenses of $0.1 million for the three months ended September 30, 2014, due to the acquisitions. The Company has included in its consolidated statements of operations revenues of $24.1 million and direct operating expenses of $6.9 million for the nine months ended September 30, 2015 and revenues of $31.0 million and direct operating expenses of $4.7 million for the nine months ended September 30, 2014 attributable to the period from February 28, 2014 to September 30, 2014, due to the acquisitions. The disclosure of net earnings is impracticable to calculate due to the full cost method of depletion.

Pro Forma Financial Information

The following unaudited summary pro forma combined consolidated statement of operations data of Diamondback for the three and nine months ended September 30, 2014 have been prepared to give effect to the February 27 and 28, 2014 acquisitions and the September 9, 2014 acquisition as if they had occurred on January 1, 2014. The pro forma data are not necessarily indicative of financial results that would have been attained had the acquisitions occurred on January 1, 2014. 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.

	Pro Forma (Unaudited)	
	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
	(in thousands)	
Revenues	$139,127	$409,520

Income from operations	63,516	186,483
Net income	43,739	102,583

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. Viper Energy Partners GP LLC, a fully-consolidated subsidiary of Diamondback, serves as the general partner of, and holds a non-economic general partner interest in, the Partnership. As of September 30, 2015, the Company owned approximately 88% of the common units of the Partnership.

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 September 30, 2014, the Partnership had distributed $148.8 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. During the three and nine months ended September 30, 2015, the Partnership distributed $15.5 million and $46.5 million, respectively, to Diamondback in respect of its common units.

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, dated June 23, 2014 (the “Partnership Agreement”). 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 with Diamondback, dated June 23, 2014, pursuant to which the Partnership agreed to 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 agreed to 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.

Other Agreements

See Note 11—Related Party Transactions for information regarding the advisory services agreement the Partnership and the General Partner entered into with Wexford Capital LP (“Wexford”).

The Partnership has entered into a secured revolving credit facility with Wells Fargo, as administrative agent sole book runner and lead arranger. See Note 8—Debt for a description of this credit facility.

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

5. PROPERTY AND EQUIPMENT

Property and equipment includes the following:

	September 30, 2015	December 31, 2014
	(in thousands)	
Oil and natural gas properties:		
Subject to depletion	$2,750,460	$2,345,077
Not subject to depletion-acquisition costs		
Incurred in 2015	421,576	—
Incurred in 2014	543,499	576,802
Incurred in 2013	71,802	130,474
Incurred in 2012	62,727	65,480
Incurred in 2011	—	764
Total not subject to depletion	1,099,604	773,520
Gross oil and natural gas properties	3,850,064	3,118,597
Accumulated depletion	(870,569)	(379,481)
Impairment	(273,737)	—
Oil and natural gas properties, net	2,705,758	2,739,116
Pipeline and gas gathering assets	7,176	7,174
Other property and equipment	48,913	48,180
Accumulated depreciation	(3,630)	(2,663)
Property and equipment, net of accumulated depreciation, depletion, amortization and impairment	$2,758,217	$2,791,807

The Company uses the full cost method of accounting for its oil and natural gas properties. Under this method, all acquisition, exploration and development costs, including certain internal costs, are capitalized and amortized on a composite unit of production method based on proved oil, natural gas liquids and natural gas reserves. 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 $4.0 million and $2.4 million for the three months ended September 30, 2015 and 2014, respectively, and $12.1 million and $7.3 million for the nine months ended September 30, 2015 and 2014, 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. Sales of oil and natural gas properties, whether or not being amortized currently, are accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil, natural gas liquids and natural gas.

Under this method of accounting, the Company is required to perform a ceiling test each quarter. The test determines a limit, or ceiling, on the book value of the proved oil and gas properties. Net capitalized costs are limited to the lower of unamortized cost net of deferred income taxes, or the cost center ceiling. The cost center ceiling is defined as the sum of (a) estimated future net revenues, discounted at 10% per annum, from proved reserves, based on the trailing

12-month unweighted average of the first-day-of-the-month price, adjusted for any contract provisions or financial derivatives, if any, that hedge the Company's oil and natural gas revenue, and excluding the estimated abandonment costs for properties with asset retirement obligations recorded on the balance sheet, (b) the cost of properties not being amortized, if any, and (c) the lower of cost or market value of unproved properties included in the cost being amortized, including related deferred taxes for differences between the book and tax basis of the oil and natural gas properties. If the net book value, including related deferred taxes, exceeds the ceiling, an impairment or non-cash writedown is required.

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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As a result of the significant decline in prices from over $91.00 per Bbl in September 2014 to a range of prices between $38.00 per Bbl and $62.00 per Bbl in 2015, the Company recorded non-cash ceiling test impairments for the nine months ended September 30, 2015 of $597.2 million, which is included in accumulated depletion. The Company did not have any impairment of its proved oil and gas properties during 2014. The impairment charge affected the Company's reported net income but did not reduce our cash flow. In addition to commodity prices, the Company's production rates, levels of proved reserves, future development costs, transfers of unevaluated properties and other factors will determine its actual ceiling test calculation and impairment analysis in future periods.

6. ASSET RETIREMENT OBLIGATIONS

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

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Asset retirement obligation, beginning of period	$8,486	$3,029
Additional liability incurred	448	567
Liabilities acquired	3,123	3,678
Liabilities settled	(4)	(10)
Accretion expense	588	303
Revisions in estimated liabilities	60	588
Asset retirement obligation, end of period	12,701	8,155
Less current portion	39	40
Asset retirement obligations - long-term	$12,662	$8,115

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. EQUITY METHOD INVESTMENTS

In October 2014, the Company paid $0.6 million for a minority interest in an entity that was formed to develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water to exploration and production companies operating in Midland, Martin and Andrews Counties, Texas. The board of this entity may also authorize the entity to offer these services to other counties in the Permian Basin and to pursue other business opportunities. The Company has committed to invest an aggregate amount of $5.0 million in this entity, and several other third parties have committed to invest an aggregate of $15.0 million. For the three and nine months ended September 30, 2015, the Company invested an additional $1.0 million and $2.7 million, respectively, in this entity. The Company will retain a minority interest after all commitments are received. The entity was formed as a limited liability company and maintains a specific ownership account for each investor, similar to a partnership capital account structure. Therefore, the Company accounts for this investment under the equity method of accounting.

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

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

	September 30, 2015	December 31, 2014
	(in thousands)	
Revolving credit facility	$10,000	$223,500
7.625 % Senior Notes due 2021	450,000	450,000
Partnership revolving credit facility	29,000	—
Total long-term debt	$489,000	$673,500

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 of September 30, 2015, the Senior Notes are fully and unconditionally guaranteed by Diamondback O&G LLC, Diamondback E&P LLC and White Fang Energy 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, National Association (“Wells Fargo”), as the trustee, as supplemented (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 with the initial purchasers on September 18, 2013, pursuant to which the Company and the subsidiary guarantors agreed to file a registration statement with respect to an offer to exchange the Senior Notes

Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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for a new issue of substantially identical debt securities registered under the Securities Act, which registration statement was declared effective by the SEC on September 15, 2014 and the exchange offer completed on October 23, 2014.

The Company’s Credit Facility

On June 9, 2014, Diamondback O&G LLC, as borrower, entered into a first amendment and on November 13, 2014, Diamondback O&G LLC entered into a second amendment to the second amended and restated credit agreement, dated November 1, 2013 (the “credit agreement”). The first amendment modified certain provisions of the credit agreement to, among other things, allow one or more of the Company’s subsidiaries to be designated as “Unrestricted Subsidiaries” that are not subject to certain restrictions contained in the credit agreement. In connection with the Viper Offering, the Partnership, the General Partner and Viper Energy Partners LLC were designated as unrestricted subsidiaries under the credit agreement. As of September 30, 2015, the credit agreement was guaranteed by Diamondback, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of Diamondback O&G LLC, the Company and the other guarantors.

The second amendment increased the maximum amount of the credit facility to $2.0 billion, modified the dates and deadlines of the credit agreement relating to the scheduled borrowing base redeterminations based on the Company’s oil and natural gas reserves and other factors and added new provisions that allow the Company to elect a commitment amount that is less than its borrowing base as determined by the lenders. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, the Company may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2015, the borrowing base was set at $725.0 million, of which the Company had elected a commitment amount of $500.0 million, and the Company had outstanding borrowings of $10.0 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 repaid (a) to the extent that the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2018.

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 September 30, 2015, the Company had $450.0 million of senior unsecured notes outstanding.

As of September 30, 2015 and December 31, 2014, 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.

The Partnership's Credit Agreement

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, which was amended August 15, 2014 to add additional lenders to the lending group, 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 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. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. As of September 30, 2015, the borrowing base remained at $175.0 million. The Partnership had $29.0 million outstanding under its credit agreement as of September 30, 2015.

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 repaid (a) to the extent that 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, purchases of margin stock, 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[1]	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

(1) EBITDAX is annualized for the four fiscal quarters ending on the last day of the fiscal quarter for which financial statements are available, beginning with the quarter ended September 30, 2014.

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 credit agreement upon the occurrence and during the continuance of any event of default. The Partnership's 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.

9. CAPITAL STOCK AND EARNINGS PER SHARE

As of September 30, 2015, Diamondback had completed the following equity offerings since January 1, 2014:

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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.

In July 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 $485.0 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In January 2015, the Company completed an underwritten public offering of 2,012,500 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $59.34 per share and the Company received net proceeds of approximately $119.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In May 2015, 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 underwriters at $72.53 per share and the Company received net proceeds of approximately $333.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2015, the Company completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $68.74 per share and the Company received net proceeds of approximately $197.6 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 September 30,					
	2015			2014		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					

Basic:						
Net income attributable to common stock	$(156,781)	65,251	$(2.40)	$43,739	55,152	$0.79
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$—	—		(53)	290	
Diluted:						
Net income attributable to common stock	$(156,781)	65,251	$(2.40)	$43,686	55,442	$0.79

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Diamondback Energy, Inc. and Subsidiaries
Notes to Consolidated Financial Statements-(Continued)
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	Nine Months Ended September 30,					
	2015			2014		
	Income	Shares	Per Share	Income	Shares	Per Share
	(in thousands, except per share amounts)					
Basic:						
Net income attributable to common stock	$(363,219)	61,727	$(5.88)	$95,081	51,489	$1.85
Effect of Dilutive Securities:						
Dilutive effect of potential common shares issuable	$—	—		16	399	
Diluted:						
Net income attributable to common stock	$(363,219)	61,727	$(5.88)	$95,097	51,888	$1.83

For the three and nine months ended September 30, 2015, there were 124,400 shares and 191,118 shares, respectively, that were not included in the computation of diluted earnings per share because their inclusion would have been anti-dilutive for the periods presented but could potentially dilute basic earnings per share in future periods.

10. EQUITY-BASED COMPENSATION

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
General and administrative expenses	$4,402	$2,069	$13,659	$5,387
Equity-based compensation capitalized pursuant to full cost method of accounting for oil and natural gas properties	1,534	2,043	5,125	4,758

Stock Options

The following table presents the Company’s stock option activity under the Company’s 2012 Equity Incentive Plan (“2012 Plan”) for the nine months ended September 30, 2015.

	Options	Weighted Average Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	313,105	$18.29		
Exercised	(150,605)	$18.05		
Outstanding at September 30, 2015	162,500	$18.51	1.29	$7,489
Vested and Expected to Vest at September 30, 2015	162,500	$18.51	1.29	$7,489
Exercisable at September 30, 2015	118,500	$17.50	1.03	$5,581

The aggregate intrinsic value of stock options that were exercised during the nine months ended September 30, 2015 and 2014 was $8.4 million and $16.8 million, respectively. As of September 30, 2015, the unrecognized compensation cost related to unvested stock options was $0.1 million. Such cost is expected to be recognized over a weighted-average period of 1.27 years.

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

Restricted Stock Units

The following table presents the Company's restricted stock units activity under the 2012 Plan during the nine months ended September 30, 2015.

	Restricted Stock Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	167,291	$49.99
Granted	98,664	$68.46
Vested	(139,671)	$43.32
Forfeited	(1,954)	$74.57
Unvested at September 30, 2015	124,330	$61.74

The aggregate fair value of restricted stock units that vested during the nine months ended September 30, 2015 and 2014 was $9.8 million and $7.2 million, respectively. As of September 30, 2015, the Company's unrecognized compensation cost related to unvested restricted stock awards and units was $5.0 million. Such cost is expected to be recognized over a weighted-average period of 1.24 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 shareholder 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. In February 2015, eligible employees received additional performance restricted stock unit awards totaling 90,249 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, 2014 to December 31, 2016 and cliff vest at December 31, 2016.

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 for the February 2015 and February 2014 awards.

	2015	2014
Grant-date fair value	$137.14	$125.63
Risk-free rate	0.49%	0.30%
Company volatility	43.36%	39.60%

The following table presents the Company's performance restricted stock units activity under the 2012 Plan for the nine months ended September 30, 2015.

	Performance Restricted Stock	Weighted Average Grant-Date

	Units	Fair Value
Unvested at December 31, 2014	79,150	$125.63
Granted	90,249	$137.14
Unvested at September 30, 2015[(1)]	169,399	$131.76

(1) A maximum of 338,798 units could be awarded based upon the Company’s final TSR ranking.

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As of September 30, 2015, the Company's unrecognized compensation cost related to unvested performance based restricted stock awards and units was $9.5 million. Such cost is expected to be recognized over a weighted-average period of 1.1 years.

Partnership Unit Options

In accordance with the Viper Energy Partners LP Long Term Incentive Plan ("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 the executive officers of the General Partner. The unit options vest approximately 33% ratably on each of the first three anniversaries of the date of grant or earlier upon a change of control (as defined in the Viper LTIP). Vested unit options will be automatically exercised upon the earlier of a change of control or the third anniversary of the grant date unless extended in accordance with the terms of the Viper LTIP (the "Exercise Date"). In the event the fair market value per unit as of the Exercise Date is less than the exercise price per option unit, the vested options will automatically terminate and become null and void on 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	%

The following table presents the unit option activity under the Viper LTIP for the nine months ended September 30, 2015.

		Weighted Average		
	Unit Options	Exercise Price	Remaining Term (in years)	Intrinsic Value (in thousands)
Outstanding at December 31, 2014	2,500,000	$26.00		
Granted	—	$—		
Outstanding at September 30, 2015	2,500,000	$—	1.75	$—
Vested and Expected to Vest at September 30, 2015	2,500,000	$—	1.75	$—
Exercisable at September 30, 2015	—	$—	0	$—

As of September 30, 2015, the unrecognized compensation cost related to unvested unit options was $6.1 million. Such cost is expected to be recognized over a weighted-average period of 1.8 years.

Phantom Units

Under the Viper LTIP, the Board of Directors of the General Partner is authorized to issue phantom units to eligible employees. The Partnership estimates the fair value of phantom units as the closing price of the Partnership's common units on the grant date of the award, which is expensed over the applicable vesting period. Upon vesting, the phantom units entitle the recipient to one common unit of the Partnership for each phantom unit.

Diamondback Energy, Inc. and Subsidiaries
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The following table presents the phantom unit activity under the Viper LTIP for the nine months ended September 30, 2015.

	Phantom Units	Weighted Average Grant-Date Fair Value
Unvested at December 31, 2014	17,776	$ 19.51
Granted	24,690	$ 15.48
Vested	(17,118)	$ 17.57
Unvested at September 30, 2015	25,348	$ 16.89

The aggregate fair value of phantom units that vested during the nine months ended September 30, 2015 was $0.3 million. As of September 30, 2015, the unrecognized compensation cost related to unvested phantom units was $0.4 million. Such cost is expected to be recognized over a weighted-average period of 1.4 years.

11. RELATED PARTY TRANSACTIONS

Immediately upon the completion of the Company's initial public offering on October 17, 2012, Wexford beneficially owned approximately 47% of the Company's outstanding common stock. As of September 30, 2015, Wexford beneficially owned less than 1% of the Company's outstanding common stock. A partner at Wexford serves as Chairman of the Board of Directors of each of the Company and the General Partner. Another partner at Wexford serves a member of the Board of Directors of the General Partner.

Administrative Services

An entity then under common management with the Company provided technical, administrative and payroll services to the Company under a shared services agreement that 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, continued on a month-to-month basis. Effective August 31, 2014, this agreement was mutually terminated.

Effective January 1, 2012, the Company entered into an additional shared services agreement with this entity. Under this agreement, the Company provided 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. Thereafter, the agreement continued on a month-to-month basis subject to the right of either party to terminate the agreement upon 30 days' prior written notice. Effective August 31, 2014, this agreement was mutually terminated. Costs that are attributable to and billed to other affiliates are reported as other income-related party.

Drilling Services

Bison Drilling and Field Services LLC ("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 September 30, 2015, the Company was not utilizing any Bison 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 and nine months ended September 30, 2014, the Company incurred total costs for services performed by

Bison of $0.9 million and $3.4 million, respectively. Bison is an affiliate of Wexford.

Effective September 9, 2013, the Company entered into a master service agreement with Panther Drilling Systems LLC ("Panther Drilling"), under which 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 and nine months ended September 30, 2015, Panther Drilling did not perform any services for the Company. For the nine months ended September 30, 2014, the Company incurred $0.3 million for services performed by Panther

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Drilling. Panther Drilling did not perform any services for the Company for the three months ended September 30, 2014. Panther Drilling is an affiliate of Wexford.

Coronado Midstream

The Company is party to a gas purchase agreement, dated May 1, 2009, as amended, with Coronado Midstream LLC, formerly known as MidMar Gas LLC, an entity that owns a gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream LLC is obligated to purchase from the Company, and the Company is obligated to sell to Coronado Midstream LLC, 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 LLC is obligated to pay the Company 87% of the net revenue received by Coronado Midstream LLC 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 LLC's gas processing plant, and 94.56% of the net revenue received by Coronado Midstream LLC from the sale of such gas components and residue gas, extracted, recovered or otherwise processed at Chevron's Headlee plant. An entity controlled by Wexford had owned an approximately 28% equity interest in Coronado Midstream LLC until Coronado Midstream LLC was sold in March 2015. Coronado Midstream LLC is no longer a related party and any revenues, production and ad valorem taxes and gathering and transportation expense after March 2015 are not classified as those attributable to a related party. The Company recognized related party revenues from Coronado Midstream LLC of $5.2 million for the three months ended March 31, 2015. The Company recognized revenues from Coronado Midstream LLC of $6.8 million and $17.2 million for the three and nine months ended September 30, 2014, respectively. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream LLC of $1.1 million for the three months ended March 31, 2015. The Company recognized production and ad valorem taxes and gathering and transportation expenses from Coronado Midstream LLC of $1.1 million and $2.8 million for the three and nine months ended September 30, 2014, respectively. As of December 31, 2014, Coronado Midstream LLC owed the Company $4.0 million for the Company's portion of the net proceeds from the sale of gas, gas products and residue gas.

Midland Corporate 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 $0.3 million and $0.7 million for the three and nine months ended September 30, 2015, respectively, under this lease. The Company paid $0.1 million and $0.3 million for the three and nine months ended September 30, 2014, respectively, under this lease.

The following table contains information regarding recent amendments to the Midland corporate lease:

Date of Amendment	Reason for Amendment	Current Monthly Base Rent	New Monthly Base Rent or Rent for Additional Space	Approx. Annual Increase of Monthly Base Rent
Second quarter 2014	Lease additional space	$25,000	$27,000	N/A
Fourth quarter 2014(1)	Lease additional space	$27,000	$53,000	4%
November 2014(2)(3)	Extend the term	N/A	N/A	N/A
April 2015	Lease additional space	N/A	$23,000	N/A

June 2015	Lease additional space	N/A	$22,000	2%

(1) The monthly rent will continue to increase approximately 4% annually on June 1 of each year during the remainder of the lease term.

(2) The lease was amended to extend the term of the lease for an additional 10-year period.

(3) Upon commencement of the extension in June 2016, the monthly base rent will increase to $94,000, with an increase of approximately 2% annually.

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Field Office Lease

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 term of the lease expires on February 28, 2018. The Company paid rent of less than $0.1 million and $0.1 million to the related party for the three and nine months ended September 30, 2015, respectively. The Company paid rent of less than $0.1 million to the related party for both the three and nine months ended September 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. During the third quarter of 2014, the Company entered into a sublease with Bison, in which Bison agreed to lease the field office space for the same term as the initial lease and agreed to pay the monthly rent of $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 $0.1 million and $0.2 million for the three and nine months ended September 30, 2014, 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 was also responsible for paying a portion of specified costs, fees and expenses associated with the operation of the premises. Effective September 23, 2014, this lease agreement was mutually terminated.

Advisory Services Agreement - The Company

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 $0.5 million, plus reasonable out-of-pocket expenses. The Advisory Services Agreement had an initial term of two years commencing on October 18, 2012, and continues 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 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 $0.1 million and $0.4 million for the three and nine months ended September 30, 2015, respectively, under the Advisory Services Agreement. The Company incurred total costs of $0.1 million and $0.4 million for the three and nine months ended September 30, 2014, respectively, under the Advisory Services Agreement.

Advisory Services Agreement- The Partnership

In connection with the closing of the Viper Offering, the Partnership and the 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 the General Partner with general financial and strategic advisory services related to the business in return for an annual fee of $0.5 million, plus reasonable out-of-pocket expenses. The Viper Advisory Services Agreement has an initial 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 the General Partner terminates such agreement, the Partnership is obligated to pay all amounts due through the remaining term. In addition, the Partnership and the General Partner have agreed to pay Wexford to-be-negotiated market-based fees approved by the conflict committee of the board of directors of the General Partner for such services as may be provided by Wexford at the Partnership’s or the General Partner’s request in connection with acquisitions and divestitures, financings or other transactions in which they may be involved. The services provided by Wexford under the Viper Advisory Services Agreement do not extend to the Partnership or General Partners day-

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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. For the three and nine months ended September 30, 2015, the Partnership incurred costs of $0.2 million and $0.5 million, respectively, under the Viper Advisory Services Agreement. For both the three and nine months ended September 30, 2014, the Partnership incurred costs of $0.1 million under the Viper Advisory Services Agreement.

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 Argus Louisiana light sweet pricing, New York Mercantile Exchange West Texas Intermediate pricing or Inter–Continental Exchange pricing for Brent crude oil.

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 September 30, 2015, the Company had open crude oil derivative positions with respect to future production as set forth in the table 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
October - December 2015	276,000	90.99

Crude Oil—NYMEX West Texas Intermediate Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
October - December 2015	460,000	84.10

Crude Oil—Inter–Continental Exchange Brent Fixed Price Swap

Production Period	Volume (Bbls)	Fixed Swap Price
October - December 2015	184,000	88.78
January - February 2016	91,000	88.72

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

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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 September 30, 2015 and December 31, 2014.

	September 30, 2015	December 31, 2014
	(in thousands)	
Gross amounts of recognized assets	$40,009	$117,541
Gross amounts offset in the Consolidated Balance Sheet	—	—
Net amounts of assets presented in the Consolidated Balance Sheet	$40,009	$117,541

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:

	September 30, 2015	December 31, 2014
	(in thousands)	
Current Assets: Derivative instruments	$40,009	$115,607
Noncurrent Assets: Derivative instruments	—	1,934
Total Assets	$40,009	$117,541

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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands)			
Change in fair value of open non-hedge derivative instruments	$(7,901)	$16,440	$(77,532)	$5,630
Gain (loss) on settlement of non-hedge derivative instruments	35,504	(1,531)	104,366	(6,207)
Gain (loss) on derivative instruments	$27,603	$14,909	$26,834	$(577)

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.

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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 September 30, 2015 and December 31, 2014.

	September 30, 2015	December 31, 2014
	(in thousands)	
Fixed price swaps:		
Quoted prices in active markets level 1	$—	$—
Significant other observable inputs level 2	40,009	117,541
Significant unobservable inputs level 3	—	—
Total	$40,009	$117,541

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 balance sheets.

	September 30, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in thousands)			
Debt:				
Revolving credit facility	$10,000	$10,000	$223,500	$223,500
7.625% Senior Notes due 2021	450,000	474,750	450,000	440,438
Partnership revolving credit facility	29,000	29,000	—	—

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 September 30, 2015 quoted market price, a Level 1 classification in the fair value hierarchy. The fair value of the Partnership's revolving credit facility approximates its carrying value based on borrowing rates available to us for bank loans with similar terms and maturities and is classified as Level 2 in the fair value hierarchy.

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Notes to Consolidated Financial Statements-(Continued)
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14. COMMITMENTS AND CONTINGENCIES

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 September 30, 2015:

Year Ending December 31,	Drilling Rig Commitments	Office and Equipment Leases
	(in thousands)	
2016	$27,317	$1,743
2017	19,892	2,012
2018	13,031	1,932
2019	—	1,797
2020	—	1,618
Thereafter	—	9,337
Total	$60,240	$18,439

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.

Litigation

The Company is one of the defendants in a lawsuit that arose after a contractor’s ditching machine cut a third party’s refined gasoline pipeline. This matter possibly could result in an adverse outcome. The estimated possible damages are in the range of $2.0 million to $4.0 million plus attorneys’ fees. The Company believes any loss would be covered by its insurance and would not have a material adverse effect on the Company’s financial condition. The Company’s financial statements do not include a loss contingency reserve for this matter.

15. GUARANTOR FINANCIAL STATEMENTS

Diamondback E&P LLC, Diamondback O&G LLC and White Fang Energy LLC (the “Guarantor Subsidiaries”) are guarantors under the Indenture relating to the Senior Notes. On June 23, 2014, in connection with the Viper Offering, the Company designated the Partnership, the General Partner and Viper Energy Partners LLC (the “Non-Guarantor Subsidiaries”) 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 combined consolidated financial information for the Company (which for purposes of this Note 16 is referred to as the “Parent”), the Guarantor Subsidiaries and the Non–Guarantor Subsidiaries on a 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.

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Condensed Consolidated Balance Sheet
September 30, 2015
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$227	$38,649	$4,951	$—	$43,827
Restricted cash	—	—	500	—	500
Accounts receivable	9	72,635	10,596	2	83,242
Intercompany receivable	2,248,015	2,980,548	—	(5,228,563)	—
Inventories	—	2,602	—	—	2,602
Other current assets	497	42,318	453	—	43,268
Total current assets	2,248,748	3,136,752	16,500	(5,228,561)	173,439
Property and equipment:					
Oil and natural gas properties, at cost, based on the full cost method of accounting	—	3,306,760	543,304	—	3,850,064
Pipeline and gas gathering assets	—	7,176	—	—	7,176
Other property and equipment	—	48,913	—	—	48,913
Accumulated depletion, depreciation, amortization and impairment	—	(1,089,767)	(59,386)	1,217	(1,147,936)
Net property and equipment	—	2,273,082	483,918	1,217	2,758,217
Investment in subsidiaries	274,184	—	—	(274,184)	—
Other assets	13,773	10,259	35,866	—	59,898
Total assets	$2,536,705				

(a) Includes the ineffective portion and amount excluded from effectiveness testing.

Derivatives and non-derivatives in net investment hedging relationships

(millions)	Gain (loss) recognized in AOCI	
	Sep. 27, 2014	Sep. 28, 2013
Foreign currency denominated long-term debt	**$ 42**	$
Total	**$ 42**	$

Derivatives not designated as hedging instruments

(millions)	Location of gain (loss) recognized in income	Gain (loss) recognized in income	
		Sep. 27, 2014	Sep. 28, 2013
Foreign currency exchange contracts	Other income (expense), net	**$ 1**	$ 1
Commodity contracts	COGS	**(61)**	(2)
Total		**$ (60)**	$ (1)

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The effect of derivative instruments on the Consolidated Statements of Income and Comprehensive Income for the year-to-date periods ended September 27, 2014 and September 28, 2013 were as follows:

Derivatives in fair value hedging relationships

(millions)	Location of gain (loss) recognized in income	Gain (loss) recognized in income(a)	
		Sep. 27, 2014	Sep. 28, 2013
Foreign currency exchange contracts	Other income (expense), net	**$ 3**	$ 2
Interest rate contracts	Interest expense	**13**	(2)
Total		**$ 16**	$

(a) Includes the ineffective portion and amount excluded from effectiveness testing.

Derivatives in cash flow hedging relationships

(millions)	Gain (loss) recognized in AOCI		Location of gain (loss) reclassified from AOCI	Gain (loss) reclassified from AOCI into income		Location of gain (loss) recognized in income (a)	Gain (loss) recognized in income(a)	
	Sep. 27, 2014	Sep. 28, 2013		**Sep. 27, 2014**	Sep. 28, 2013		**Sep. 27, 2014**	Sep. 28, 2013
Foreign currency exchange contracts	**$ 13**	$ 8	COGS	**$ 2**	$ 7	Other income (expense), net	**$ (3)**	$
Foreign currency exchange contracts	**4**	(2)	SGA expense	**5**	1	Other income (expense), net		
Interest rate contracts	**(43)**		Interest expense	**9**	3	N/A		
Commodity contracts		(1)	COGS	**(5)**	(7)	Other income (expense), net		
Total	**$ (26)**	$ 5		**$ 11**	$ 4		**$ (3)**	$

(a) Includes the ineffective portion and amount excluded from effectiveness testing.

Derivatives and non-derivatives in net investment hedging relationships

(millions)	Gain (loss) recognized in AOCI	
	Sep. 27, 2014	Sep. 28, 2013
Foreign currency denominated long-term debt	**$ 47**	$
Total	**$ 47**	$

Derivatives not designated as hedging instruments

(millions)	Location of gain (loss) recognized in income	Gain (loss) recognized in income	
		Sep. 27, 2014	Sep. 28, 2013
Foreign currency exchange contracts	COGS	**$**	$ 2
Foreign currency exchange contracts	Other income (expense), net	**(1)**	
Interest rate contracts	Interest expense	**(4)**	
Commodity contracts	COGS	**(66)**	(26)
Total		**$ (71)**	$ (24)

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During the next 12 months, the Company expects $2 million of net deferred losses reported in AOCI at September 27, 2014 to be reclassified to income, assuming market rates remain constant through contract maturities.

Certain of the Company s derivative instruments contain provisions requiring the Company to post collateral on those derivative instruments that are in a liability position if the Company s credit rating is at or below BB+ (S&P), or Baa1 (Moody s). The fair value of all derivative instruments with credit-risk-related contingent features in a liability position on September 27, 2014 was $79 million. If the credit-risk-related contingent features were triggered as of September 27, 2014, the Company would be required to post additional collateral of $64 million. In addition, certain derivative instruments contain provisions that would be triggered in the event the Company defaults on its debt agreements. There were no collateral posting requirements as of September 27, 2014 triggered by credit-risk-related contingent features, however, there was $15 million of collateral posted in connection with reciprocal collateralization agreements as discussed under Counterparty credit risk concentration and collateral requirements below.

Fair Value Measurements on a Nonrecurring Basis

As part of Project K the Company will be consolidating the usage of and disposing certain long-lived assets, including manufacturing facilities and Corporate owned assets over the term of the program. See Note 3 for more information regarding Project K.

In the quarter ended September 27, 2014, long-lived assets of $24 million, related to a manufacturing facility in our U.S. Snacks segment, were written down to an estimated fair value of $3 million due to Project K activities. The Company s calculation of the fair value of long-lived assets is based on Level 3 inputs, including market comparables, market trends and the condition of the assets.

The following table presents level 3 assets that were measured at fair value on the Consolidated Balance Sheet on a nonrecurring basis as of September 27, 2014:

(millions)	Fair Value	Total Loss
Description:		
Long-lived assets	$ 3	$ (21)
Total	$ 3	$ (21)

Financial instruments

The carrying values of the Company s short-term items, including cash, cash equivalents, accounts receivable, accounts payable and notes payable approximate fair value. The fair value of the Company s long-term debt, which are level 2 liabilities, is calculated based on broker quotes and was as follows at September 27, 2014:

(millions)	Fair Value	Carrying Value
Current maturities of long-term debt	$ 607	$ 607
Long-term debt	6,471	5,963
Total	$ 7,078	$ 6,570

Counterparty credit risk concentration and collateral requirements

The Company is exposed to credit loss in the event of nonperformance by counterparties on derivative financial and commodity contracts. Management believes a concentration of credit risk with respect to derivative counterparties is limited due to the credit ratings and use of master netting and reciprocal collateralization agreements with the counterparties and the use of exchange-traded commodity contracts.

Master netting agreements apply in situations where the Company executes multiple contracts with the same counterparty. Certain counterparties represent a concentration of credit risk to the Company. If those counterparties fail to perform according to the terms of derivative contracts, this would result in a loss to the Company. As of September 27, 2014, the Company was not in a significant net asset position with any counterparties with which a master netting agreement would apply.

For certain derivative contracts, reciprocal collateralization agreements with counterparties call for the posting of collateral in the form of cash, treasury securities or letters of credit if a fair value loss position to the Company or its counterparties exceeds a certain amount. In addition, the Company is required to maintain cash margin accounts in connection with its open positions for exchange-traded commodity derivative instruments executed with the counterparty that are subject to enforceable netting agreements. As of September 27, 2014 the Company had posted collateral of $15 million in the form of cash, which was reflected as an increase in accounts receivable, net on the Consolidated Balance Sheet. As of September 27, 2014 the Company posted $49 million in margin deposits for exchange-traded commodity derivative instruments, which was reflected as an increase in accounts receivable, net.

Management believes concentrations of credit risk with respect to accounts receivable is limited due to the generally high credit quality of the Company s major customers, as well as the large number and geographic dispersion of smaller customers. However, the Company conducts a disproportionate amount of business with a small number of large multinational grocery retailers, with the five largest accounts encompassing approximately 27% of consolidated trade receivables at September 27, 2014.

Note 10 Contingencies

In connection with the Company s on-going labor negotiations with the union representing the work-force at our Memphis, TN cereal production facility, the National Labor Relations Board filed a complaint alleging unfair labor practices under the National Labor Relations Act in March 2014. In July, 2014, a U.S. District Court judge ruled that the Memphis employees were entitled to return to work while the underlying litigation continues and employees have subsequently returned to work. This ruling is not expected to have a material effect on the production or distribution of products from the Memphis, TN facility or a material financial impact on the Company. As of September 27, 2014, the Company has not recorded a liability related to this matter due to the uncertainty of any potential outcome. The Company will continue to evaluate the likelihood of potential outcomes for this case as the litigation continues.

Note 11 Reportable segments

Kellogg Company is the world s leading producer of cereal, second largest producer of cookies and crackers, and a leading producer of savory snacks and frozen foods. Additional product offerings include toaster pastries, cereal bars, fruit-flavored snacks and veggie foods. Kellogg products are manufactured and marketed globally. Principal markets for these products include the United States and United Kingdom.

The Company currently manages its operations through eight operating segments that are based on product category or geographic location. These operating segments are evaluated for similarity with regards to economic characteristics, products, production processes, types or classes of customers, distribution methods and regulatory environments to determine if they can be aggregated into reportable segments. The reportable segments are discussed in greater detail below.

U.S. Morning Foods includes cereal, toaster pastries, health and wellness bars, and beverages.

U.S. Snacks includes products such as cookies, crackers, cereal bars, savory snacks and fruit-flavored snacks.

U.S. Specialty includes the food service, convenience and Girl Scouts businesses. The food service business is mostly non-commercial, servicing institutions such as schools and hospitals.

North America Other includes the U.S. Frozen and Canada operating segments. As these operating segments are not considered economically similar enough to aggregate with other operating segments and are immaterial for separate disclosure, they have been grouped together as a single reportable segment.

The three remaining reportable segments are based on geographic location Europe, which consists principally of European countries; Latin America, which is comprised of Central and South America and includes Mexico; and Asia Pacific, which is comprised of South Africa, Australia and other Asian and Pacific markets.

The measurement of reportable segment results is based on segment operating profit which is generally consistent with the presentation of operating profit in the Consolidated Statement of Income. Intercompany transactions between operating segments were insignificant in all periods presented.

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(millions)	Quarter ended September 27, 2014	Quarter ended September 28, 2013	Year-to-date period ended September 27, 2014	Year-to-date period ended September 28, 2013
Net sales				
U.S. Morning Foods	**$ 841**	$ 883	**$ 2,522**	$ 2,657
U.S. Snacks	**849**	886	**2,645**	2,704
U.S. Specialty	**270**	281	**918**	932
North America Other	**369**	382	**1,111**	1,173
Europe	**726**	729	**2,206**	2,144
Latin America	**320**	302	**918**	914
Asia Pacific	**264**	253	**746**	767
Consolidated	**$ 3,639**	$ 3,716	**$ 11,066**	$ 11,291
Operating profit				
U.S. Morning Foods	**$ 118**	$ 132	**$ 389**	$ 475
U.S. Snacks	**67**	105	**292**	341
U.S. Specialty	**59**	70	**209**	210
North America Other	**58**	70	**192**	223
Europe	**61**	74	**181**	220
Latin America	**50**	39	**145**	129
Asia Pacific	**16**	25	**32**	63
Total Reportable Segments	**429**	515	**1,440**	1,661
Corporate	**(64)**	(11)	**6**	(84)
Consolidated	**$ 365**	$ 504	**$ 1,446**	$ 1,577

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KELLOGG COMPANY

PART I FINANCIAL INFORMATION

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

Business overview

The following Management s Discussion and Analysis of Financial Condition and Results of Operations (MD&A) is intended to help the reader understand Kellogg Company, our operations and our present business environment. MD&A is provided as a supplement to, and should be read in conjunction with, our Consolidated Financial Statements and the accompanying notes thereto contained in Item 1 of this report.

For more than 100 years, consumers have counted on Kellogg for great-tasting, high-quality and nutritious foods. Kellogg is the world s leading producer of cereal, second largest producer of cookies and crackers, and a leading producer of savory snacks and frozen foods. Additional product offerings include toaster pastries, cereal bars, fruit-flavored snacks and veggie foods. Kellogg products are manufactured and marketed globally.

We manage our operations through eight operating segments that are based on product category or geographic location. These operating segments are evaluated for similarity with regards to economic characteristics, products, production processes, types or classes of customers, distribution methods and regulatory environments to determine if they can be aggregated into reportable segments. We report results of operations in the following reportable segments: U.S. Morning Foods; U.S. Snacks; U.S. Specialty; North America Other; Europe; Latin America; and Asia Pacific. The reportable segments are discussed in greater detail in Note 11 within Notes to Consolidated Financial Statements.

We manage our Company for sustainable performance defined by our long-term annual growth targets. These targets are 3 to 4% for internal net sales, mid-single-digit (4 to 6%) for underlying internal operating profit, and high-single-digit (7 to 9%) for currency-neutral comparable diluted net earnings per share.

During 2013 we announced Project K, a four-year efficiency and effectiveness program. The program is expected to generate a significant amount of savings that will be invested in key strategic areas of focus for the business. We expect that this investment will drive future growth in revenues, gross margin, operating profit, and cash flow. See the Restructuring and cost reduction activities section for more information.

Comparability

Internal net sales growth excludes the impact of foreign currency translation and, if applicable, acquisitions, dispositions and integration costs associated with the acquisition of the *Pringles*® business (Pringles).

Comparability of certain financial measures is impacted significantly by two types of charges: 1) Mark-to-market adjustments that are recorded for pensions and commodity derivative contracts; and 2) Charges related to restructuring and cost reduction activities. To provide increased transparency and assist in understanding our underlying operating performance we use non-GAAP financial measures within the MD&A that exclude the impact of these charges. These non-GAAP financial measures include underlying gross margin, underlying gross profit, underlying SGA%, underlying operating margin, underlying operating profit, underlying operating profit growth, underlying income taxes, underlying effective tax rate, and underlying net income attributable to Kellogg Company.

Underlying internal operating profit growth excludes the impact of foreign currency translation and, if applicable, acquisitions, dispositions, integration costs associated with the acquisition of Pringles, mark-to-market adjustments, and charges related to restructuring and cost reduction activities.

Additionally, integration costs associated with the acquisition of Pringles are excluded from comparable basic earnings per share (EPS), comparable diluted EPS, and comparable diluted EPS growth.

Financial results

For the quarter ended September 27, 2014, our reported net sales declined by 2.1% and internal net sales declined by 1.7%. We experienced internal net sales declines in U.S. Morning Foods, U.S. Snacks, U.S. Specialty, North America Other, and Europe. Internal net sales grew in

Latin America and Asia Pacific. Reported operating profit declined by 27.5%, and underlying internal operating profit declined by 1.8%. The decline in underlying internal operating profit was driven by softer sales primarily in U.S. Morning Foods, U.S. Snacks, and U.S. Specialty. This was partially offset by net cost deflation, continued discipline in overhead control, reduced incentive compensation to align with performance, and slightly lower investment in brand-building.

Reported diluted EPS of $.62 for the quarter was down 31.1% compared to the prior year of $.90. Comparable diluted EPS of $.94 for the quarter was down 3.1% compared to the prior year of $.97.

As a result of 2014 incentive compensation being reduced in the current quarter to align with performance and the anticipated re-establishment of usual incentive compensation levels in 2015, we expect that increased incentive compensation will result in a 2%-3% headwind for full-year results in 2015.

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Reconciliation of certain non-GAAP Financial Measures

	Quarter ended		Year-to-date period ended	
Consolidated results	**September 27, 2014**	September 28, 2013	**September 27, 2014**	September 28, 2013
Reported operating profit	**$ 365**	$ 504	**$ 1,446**	$ 1,577
Mark-to-market (a)	**(66)**	2	**38**	(59)
Restructuring and cost reduction activities (b)	**(92)**	(29)	**(224)**	(49)
Underlying operating profit (c)	**$ 523**	$ 531	**$ 1,632**	$ 1,685
Reported income taxes	**$ 86**	$ 124	**$ 373**	$ 398
Mark-to-market (a)	**(25)**		**7**	(19)
Restructuring and cost reduction activities (b)	**(24)**	(8)	**(62)**	(15)
Underlying income taxes (c)	**$ 135**	$ 132	**$ 428**	$ 432
Reported effective income tax rate	**27.7%**	27.4%	**28.6%**	28.6%
Mark-to-market (a)	**(1.3)%**		**(0.3)%**	(0.2)%
Restructuring and cost reduction activities (b)	**0.5%**	(0.3)%	**0.2%**	0.0%
Underlying effective income tax rate (c)	**28.5%**	27.7%	**28.7%**	28.8%
Reported net income attributable to Kellogg Company	**$ 225**	$ 326	**$ 926**	$ 989
Mark-to-market (a)	**(41)**	2	**31**	(40)
Restructuring and cost reduction activities (b)	**(68)**	(21)	**(162)**	(34)
Underlying net income attributable to Kellogg Company (c)	**$ 334**	$ 345	**$ 1,057**	$ 1,063
Reported basic EPS	**$ 0.63**	$ 0.90	**$ 2.58**	$ 2.72
Mark-to-market (a)	**(0.11)**		**0.09**	(0.12)
Pringles integration costs	**(0.02)**	(0.02)	**(0.05)**	(0.09)
Restructuring and cost reduction activities (b)	**(0.19)**	(0.05)	**(0.45)**	(0.09)
Comparable basic EPS (d)	**$ 0.95**	$ 0.97	**$ 2.99**	$ 3.02
Comparable basic EPS growth (d)	**(2.1)%**	2.1%	**(1.0)%**	1.3%
Reported diluted EPS	**$ 0.62**	$ 0.90	**$ 2.56**	$ 2.70
Mark-to-market (a)	**(0.11)**		**0.08**	(0.12)
Pringles integration costs	**(0.02)**	(0.02)	**(0.05)**	(0.09)
Restructuring and cost reduction activities (b)	**(0.19)**	(0.05)	**(0.45)**	(0.09)
Comparable diluted EPS (d)	**$ 0.94**	$ 0.97	**$ 2.98**	$ 3.00
Comparable diluted EPS growth (d)	**(3.1)%**	2.1%	**(0.7)%**	1.0%

(a) Includes mark-to-market adjustments for pension plans and commodity contracts as reflected in cost of goods sold. Actuarial gains/losses for pension plans are recognized in the year they occur. A portion of these mark-to-market adjustments were capitalized as inventoriable cost at the end of 2013 and 2012. These amounts have been recognized in the first quarter of 2014 and 2013, respectively. During the third quarter of 2014, we remeasured the benefit obligation for an impacted other nonpension postretirement plan. The remeasurement resulted in a mark-to-market loss of $7 million primarily due to a lower discount rate. Mark-to-market adjustments for commodities reflect the changes in the fair value of contracts for the difference between contract and market prices for the underlying commodities. The resulting gains/losses are recognized in the quarter they occur.

(b) Costs incurred related primarily to the execution of Project K, a global four-year efficiency and effectiveness program. The focus of the program will be to strengthen existing businesses in core markets, increase growth in developing and emerging markets, and drive an increased level of value-added innovation. The program is expected to provide a number of benefits, including an optimized supply chain infrastructure, the implementation of global business services, and a new global focus on categories. The 2013 periods presented have been recast to exclude all restructuring and cost reduction activities from underlying and comparable results. Previously, only costs associated with Project K were excluded from underlying and comparable results.

(c) Underlying operating profit, underlying income taxes, underlying effective income tax rate, and underlying net income attributable to Kellogg Company are non-GAAP measures that exclude the impact of pension and commodity mark-to-market adjustments and restructuring and cost reduction activities. We believe the use of such non-GAAP measures provides increased transparency and assists in understanding underlying operating performance. These non-GAAP measures are reconciled directly to the comparable measures in accordance with U.S. GAAP within this table.

(d) Comparable EPS is a non-GAAP measure that excludes the impact of mark-to-market adjustments on pension plans and commodity contracts, the impact of Project K costs, and the impact of integration costs related to the acquisition of the Pringles business.

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Net sales and operating profit

The following tables provide an analysis of net sales and operating profit performance for the third quarter of 2014 versus 2013:

(dollars in millions)	U.S. Morning Foods	U.S. Snacks	U.S. Specialty	North America Other	Europe	Latin America	Asia Pacific	Corp-orate	Consol-idated
2014 net sales	**$ 841**	**$ 849**	**$ 270**	**$ 369**	**$ 726**	**$ 320**	**$ 264**	**$**	**$ 3,639**
2013 net sales	**$ 883**	**$ 886**	**$ 281**	**$ 382**	**$ 729**	**$ 302**	**$ 253**	**$**	**$ 3,716**
% change - 2014 vs. 2013:									
As Reported	**(4.7)%**	**(4.2)%**	**(4.1)%**	**(3.5)%**	**(0.6)%**	**6.2%**	**4.8%**	**%**	**(2.1)%**
Acquisitions /Divestitures	%	%	%	%	%	%	%	%	%
Integration impact (a)	%	%	%	%	%	%	.6%	%	%
Foreign currency impact	%	%	%	(2.4)%	%	(1.1)%	(.8)%	%	(.4)%
Internal business (b)	**(4.7)%**	**(4.2)%**	**(4.1)%**	**(1.1)%**	**(0.6)%**	**7.3%**	**5.0%**	**%**	**(1.7)%**

(dollars in millions)	U.S. Morning Foods	U.S. Snacks	U.S. Specialty	North America Other	Europe	Latin America	Asia Pacific	Corp-orate	Consol-idated
2014 operating profit	**$ 118**	**$ 67**	**$ 59**	**$ 58**	**$ 61**	**$ 50**	**$ 16**	**$ (64)**	**$ 365**
2013 operating profit	**$ 132**	**$ 105**	**$ 70**	**$ 70**	**$ 74**	**$ 39**	**$ 25**	**$ (11)**	**$ 504**
% change - 2014 vs. 2013:									
As Reported	**(10.5)%**	**(36.2)%**	**(14.2)%**	**(18.2)%**	**(17.4)%**	**29.5%**	**(32.1)%**	**(512.6)%**	**(27.5)%**
Acquisitions/Divestitures	%	%	%	%	%	%	%	%	%
Integration impact (a)	%	%	%	.3%	.8%	.9%	3.8%	(27.4)%	.5%
Foreign currency impact	(.1)%	%	%	(2.6)%	.6%	(.8)%	(1.4)%	16.1%	(.3)%
Mark-to-market (c)	%	%	%	%	%	%	%	(611.6)%	(13.1)%
Restructuring and cost reduction activities (d)	(6.7)%	(26.3)%	.2%	(2.7)%	(22.6)%	9.6%	(39.8)%	(149.3)%	(12.8)%
Underlying internal (e)	**(3.7)%**	**(9.9)%**	**(14.4)%**	**(13.2)%**	**3.8%**	**19.8%**	**5.3%**	**259.6%**	**(1.8)%**

(a) Includes impact of integration costs associated with the Pringles acquisition.

(b) Internal net sales growth for 2014 excludes the impact of acquisitions, divestitures, integration costs and impact of foreign currency translation. Internal net sales growth is a non-GAAP financial measure which is reconciled to the directly comparable measure in accordance with U.S. GAAP within these tables.

(c) Includes mark-to-market adjustments for pension plans and commodity contracts as reflected in cost of goods sold. Actuarial gains/losses for pension plans are recognized in the year they occur. A portion of these mark-to-market adjustments were capitalized as inventoriable cost at the end of 2013 and 2012. These amounts have been recognized in the first quarter of 2014 and 2013, respectively. During the third quarter of 2014, we remeasured the benefit obligation for an impacted other nonpension postretirement plan. The remeasurement resulted in a mark-to-market loss of $7 million primarily due to a lower discount rate. Mark-to-market adjustments for commodities reflect the changes in the fair value of contracts for the difference between contract and market prices for the underlying commodities. The resulting gains/losses are recognized in the quarter they occur.

(d) Costs incurred related primarily to the execution of Project K, a global four-year efficiency and effectiveness program. The focus of the program will be to strengthen existing businesses in core markets, increase growth in developing and emerging markets, and drive an increased level of value-added innovation. The program is expected to provide a number of benefits, including an optimized supply chain infrastructure, the implementation of global business services, and a new global focus on categories. The 2013 periods presented have been recast to exclude all restructuring and cost reduction activities from underlying and comparable results. Previously, only costs associated with Project K were excluded from underlying and comparable results.

(e) Underlying internal operating profit growth excludes the impact of foreign currency translation, pension plans and commodity contracts mark-to-market adjustments, costs related to restructuring and cost reduction activities, and if applicable, acquisitions, dispositions, and integration costs associated with the acquisition of Pringles. We believe the use of this non-GAAP measure provides increased transparency and assists in understanding underlying operating performance. This non-GAAP measure is reconciled to the directly comparable measure in accordance with U.S. GAAP within this table.

U.S. Morning Foods

Internal net sales for U.S. Morning Foods declined 4.7% as a result of decreased volume and unfavorable pricing/mix. This segment consists of cereal, toaster pastries, health and wellness bars, and beverages. The cereal category continued to decline during the quarter despite our investments behind category-building programs that started in the second quarter. We realized improvement in our consumption trends, particularly in our kids brands. However, the improvements were less than we had expected. We plan to continue our investment behind category-building programs for the remainder of the year. However, we expect our cereal consumption to remain down over the remainder of the year. We continued to see weakness in *Special K*® as it faces headwinds from evolving consumer trends regarding weight management. As a result, we are changing the positioning of the brand from a focus on dieting to weight wellness. This focus will stress the role that *Special K*® plays in a healthy lifestyle. We plan to reinvent all aspects of the brand in 2015, including innovation, packaging, advertising, and consumer promotions. Each of these will highlight *Special K*® s position as part of a weight wellness program. New packaging and advertising will highlight the simplicity and goodness of the food, new consumer promotions will help consumers meet their goals, and innovation will directly appeal to consumer trends through *Special K*® Protein, *Special K*® Gluten Free, *Special K*® Granola, and additional hot cereal offerings. Toaster pastries reported a sales decline for the quarter as a result of difficult comparisons due to the peanut butter innovations launched in 2013, and the timing of new introductions this year. We plan to introduce a new PB&J innovation in November, and believe that this business will return to growth. Beverages continued to report increased consumption resulting from expanded distribution and innovations.

Underlying internal operating profit in U.S. Morning Foods declined 3.7% due to the unfavorable sales performance and a high-single-digit increase in cereal brand-building investment. This was partially offset by net cost deflation, a decrease in brand-building investment behind health and wellness bars and beverages, and continued discipline in overhead control.

U.S. Snacks

Internal net sales in U.S. Snacks declined 4.2% as a result of decreased volume partially offset by favorable pricing/mix. This segment consists of crackers, cereal bars, cookies, savory snacks, and fruit-flavored snacks. Crackers posted a sales decline, but gained share as a result of the continued success of *Cheez-It*® innovations and core products in the *Townhouse*®, and *Club*® brands due to brand-building support and sales execution. *Cheez-It*®, *Townhouse*®, and *Club*® all reported solid consumption and share gains. The bars business declined for the quarter due to continued weakness in the *Special K*® and *Fiber Plus*® brands. The issues with these brands are similar to what we have experienced in the cereal category. To address these issues we have new products and activity planned for introduction in the fourth quarter and next year. *Rice Krispies Treats*® and *Nutri-grain*® both gained share during the quarter. The *Rice Krispies Treats*® performance was the result of good core growth and an innovation launch. We expect this segment to remain challenging for the balance of the year. The cookies business declined in the quarter, resulting in lost share, although both *Chips Deluxe*® *and Fudge Shoppe*® gained share. We continued to experience soft performance in our 100-calorie packs business, and the negative impact of a SKU rationalization initiative with impacts expected into early next year. Savory snacks reported solid sales growth and held share for the quarter behind the performance of the core business, Grab n Go, and the new *Pringles*® Tortilla product.

Underlying internal operating profit in U.S. Snacks declined by 9.9% due to unfavorable sales performance and net cost inflation. This was partially offset by continued discipline in overhead control and a decrease in brand-building investment.

U.S. Specialty

Internal net sales in U.S. Specialty declined 4.1% as a result of decreased volume partially offset by favorable pricing/mix. Sales declines were the result of supply issues with a co-packer and an inventory deload as a customer shifted from warehouse to direct delivery. These issues had a significant impact on the business. Excluding these issues, we saw a much better performance driven in part by good results from innovations in Foodservice while gaining share in a number of segments within Foodservice and Convenience businesses.

Underlying internal operating profit in U.S. Specialty declined by 14.4% due to the unfavorable sales performance. This was partially offset by discipline in overhead control.

North America Other

Internal net sales in North America Other (U.S. Frozen and Canada) declined 1.1% due to unfavorable pricing/mix which was partially offset by increased volumes. The U.S. Frozen business reported a slight decline due to product mix costs associated with the launch of new products. New *Eggo*® Bites continued to do well in the quarter, and we launched new *Eggo*® handheld sandwiches in September. These sandwiches build on the great brand-value of *Eggo*® and combine it with the on-trend handheld-sandwich category. This is the first all-family offering in this segment and we are excited about its potential. Canada also reported a slight decline in sales although volumes increased at a low single-digit rate. We gained share in most categories and realized double-digit consumption growth in savory snacks as the launch of *Pringles*® Tortilla has performed well.

Underlying internal operating profit in North America Other declined 13.2% primarily due to unfavorable sales performance and increased brand-building investment. This was partially offset by continued discipline in overhead control.

Europe

Internal net sales for Europe declined 0.6% as a result of decreased volume and unfavorable pricing/mix. Cereal category consumption remains soft in most developed markets. While the performance posted by individual markets was largely as expected, our most significant challenge in the region remains the performance of *Special K*®. We have initiatives intended to address this performance planned in 2015 including new communication, an upgrade to the food, improvement in packaging, and better promotional activities. In the UK market, our cereal programs are showing early signs of success. The parent-brand Origins program, and the back-to-school themed program both achieved retail support and execution which drove strong volume improvement in the quarter. Savory snacks reported solid net sales growth in the quarter driven by focus on improving availability, visibility, and awareness. Investment in brand-building for *Pringles*® increased at a double-digit rate and we saw good results from the summer speaker-can promotion and execution at retail.

Underlying internal operating profit in Europe improved 3.8% due to net cost deflation and decreased brand-building investment. This was partially offset by unfavorable sales performance and increased overhead spending.

Latin America

Latin America s internal net sales improved 7.3% due to favorable pricing/mix which was partially offset by decreased volume. This was the result of growth in Venezuela, Mexico, Mercosur, and the Pringles business as well as strong pricing gains in a majority of our markets. The cereal business posted good results, although we saw some competitive price promotions in Mexico which affected selected segments late in the quarter. The Colombian and Venezuelan businesses gained share as a result of success in the children s and all-family segments. The *Special K*® brand has regained momentum in Venezuela as the result of increased availability and in Mexico as the result of commercial initiatives. The underlying momentum of the savory snacks business continues, driven by strong commercial programs, innovation, and good execution.

Underlying internal operating profit in Latin America improved by 19.8% due to favorable sales performance resulting from strong pricing realization. This was partially offset by net cost inflation and a double-digit increase in brand-building investment.

Asia Pacific

Internal net sales in Asia Pacific increased 5.0% as a result of increased volume and favorable pricing/mix. The sales increase was the result of double-digit growth in the Asian markets and the savory snacks business across the region. This sales performance was partially offset by continued weakness in the Australian cereal category. The decline in Australia was a sequential improvement from the results posted in the first half of the year. Performance in the quarter benefitted from *Special K*® innovation and the Breakfast for Better Days parent-brand activity.

Underlying internal operating profit in Asia Pacific increased by 5.3% due to favorable sales performance and net cost deflation. This was partially offset by increased overhead spending and increased brand-building investment.

Corporate

Underlying internal operating profit for Corporate improved as a result of reduced pension costs and discipline in overhead control.

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The following table provides an analysis of net sales and operating profit performance for the year-to-date periods of 2014 as compared to 2013.

(dollars in millions)	U.S. Morning Foods	U.S. Snacks	U.S. Specialty	North America Other	Europe	Latin America	Asia Pacific	Corp-orate	Consol-idated
2014 net sales	**$ 2,522**	**$ 2,645**	**$ 918**	**$ 1,111**	**$ 2,206**	**$ 918**	**$ 746**	**$**	**$ 11,066**
2013 net sales	**$ 2,657**	**$ 2,704**	**$ 932**	**$ 1,173**	**$ 2,144**	**$ 914**	**$ 767**	**$**	**$ 11,291**
% change - 2014 vs. 2013:									
As Reported	**(5.0)%**	**(2.2)%**	**(1.5)%**	**(5.3)%**	**2.9%**	**0.5%**	**(2.6)%**	**%**	**(2.0)%**
Acquisitions/Divestitures	%	%	%	%	%	%	(.1)%	%	%
Integration impact (a)	%	%	%	%	%	%	0.4%	%	%
Foreign currency impact	%	%	%	(2.6)%	3.4%	(2.4)%	(4.2)%	%	(.1)%
Internal business (b)	**(5.0)%**	**(2.2)%**	**(1.5)%**	**(2.7)%**	**(0.5)%**	**2.9%**	**1.3%**	**%**	**(1.9)%**

(dollars in millions)	U.S. Morning Foods	U.S. Snacks	U.S. Specialty	North America Other	Europe	Latin America	Asia Pacific	Corp-orate	Consol-idated
2014 operating profit	**$ 389**	**$ 292**	**$ 209**	**$ 192**	**$ 181**	**$ 145**	**$ 32**	**6**	**$ 1,446**
2013 operating profit	**$ 475**	**$ 341**	**$ 210**	**$ 223**	**$ 220**	**$ 129**	**$ 63**	**(84)**	**$ 1,577**
% change - 2014 vs. 2013:									
As Reported	**(18.1)%**	**(14.6)%**	**(0.1)%**	**(14.2)%**	**(17.9)%**	**12.3%**	**(48.6)%**	**107.5%**	**(8.3)%**
Acquisitions/Divestitures	%	%	%	%	%	%	1.2%	%	0.1%
Integration impact (a)	%	2.9%	%	0.4%	(.5)%	0.6%	5.2%	(18.2)%	1.2%
Foreign currency impact	%	%	%	(3.0)%	5.2%	2.0%	(3.3)%	27.2%	0.4%
Mark-to-market (c)	%	%	%	%	%	%	%	80.6%	5.7%
Restructuring and cost reduction activities (d)	(6.6)%	(9.5)%	0.2%	(4.4)%	(25.6)%	(1.5)%	(26.1)%	(97.7)%	(10.8)%
Underlying internal (e)	**(11.5)%**	**(8.0)%**	**(0.3)%**	**(7.2)%**	**3.0%**	**11.2%**	**(25.6)%**	**115.6%**	**(4.9)%**

(a) Includes impact of integration costs associated with the Pringles acquisition.

(b) Internal net sales growth for 2014 excludes the impact of acquisitions, divestitures, integration costs and impact of foreign currency translation. Internal net sales growth is a non-GAAP financial measure which is reconciled to the directly comparable measure in accordance with U.S. GAAP within these tables.

(c) Includes mark-to-market adjustments for pension plans and commodity contracts as reflected in cost of goods sold. Actuarial gains/losses for pension plans are recognized in the year they occur. A portion of these mark-to-market adjustments were capitalized as inventoriable cost at the end of 2013 and 2012. These amounts have been recognized in the first quarter of 2014 and 2013, respectively. During the third quarter of 2014, we remeasured the benefit obligation for an impacted other nonpension postretirement plan. The remeasurement resulted in a mark-to-market loss of $7 million primarily due to a lower discount rate. Mark-to-market adjustments for commodities reflect the changes in the fair value of contracts for the difference between contract and market prices for the underlying commodities. The resulting gains/losses are recognized in the quarter they occur.

(d) Costs incurred related primarily to the execution of Project K, a global four-year efficiency and effectiveness program. The focus of the program will be to strengthen existing businesses in core markets, increase growth in developing and emerging markets, and drive an increased level of value-added innovation. The program is expected to provide a number of benefits, including an optimized supply chain infrastructure, the implementation of global business services, and a new global focus on categories. The 2013 periods presented have been recast to exclude all restructuring and cost reduction activities from underlying and comparable results. Previously, only costs associated with Project K were excluded from underlying and comparable results.

(e)

Underlying internal operating profit growth excludes the impact of foreign currency translation, pension plans and commodity contracts mark-to-market adjustments, costs related to restructuring and cost reduction activities, and if applicable, acquisitions, dispositions, and integration costs associated with the acquisition of Pringles. We believe the use of this non-GAAP measure provides increased transparency and assists in understanding underlying operating performance. This non-GAAP measure is reconciled to the directly comparable measure in accordance with U.S. GAAP within this table.

U.S. Morning Foods

Year-to-date internal net sales for U.S. Morning Foods declined 5.0% due to weakness in both the cereal and toaster pastries categories. We are investing behind cereal category-building messaging, but expect that cereal category consumption will be down for the remainder of the year. Toaster pastries performance is the result of difficult comparisons due to the peanut butter innovations launched in 2013, and the timing of new introductions this year. We plan to introduce a new PB&J innovation in November, and believe that this business will return to growth.

Year-to-date underlying internal operating profit has declined 11.5% in U.S. Morning Foods as a result of unfavorable sales performance and increased brand-building investment which was partially offset by net cost deflation and continued discipline in overhead control.

U.S. Snacks

Year-to-date internal net sales for U.S. Snacks declined approximately 2.2% due to declines in our bars business, soft performance in our 100-calorie packs business, and a SKU rationalization initiative which negatively impacted sales. Crackers and savory snacks have posted growth resulting from innovations and improved in-store execution.

Year-to-date underlying internal operating profit in U.S. Snacks declined 8.0% as a result of unfavorable sales performance and net cost inflation, which was partially offset by reduced brand-building investment and continued discipline in overhead control.

U.S. Specialty

Year-to-date internal net sales for U.S. Specialty declined by 1.5% as the business has been impacted negatively by weather early in the year, supply issues with a co-packer and an inventory deload as a customer shifted from warehouse to direct delivery. Excluding these issues, the business has performed well as a result of innovations and distribution gains.

Year-to-date underlying internal operating profit in U.S. Specialty declined 0.3% as a result of unfavorable sales performance which was partially offset by net cost deflation.

North America Other

Year-to-date internal net sales for North America Other declined by 2.7% due primarily to the U.S. Frozen business reporting sales declines resulting partially from comparisons to strong prior-year growth behind innovation activity.

Year-to-date underlying internal operating profit in North America Other declined 7.2% due to unfavorable sales performance which was partially offset by net cost deflation.

Europe

Year-to-date internal net sales for Europe declined by 0.5% due to softness in the cereal category in most developed markets, partially offset by general consumption growth realized in emerging markets. Savory snacks reported consumption and share growth during the year.

Year-to-date underlying internal operating profit in Europe increased 3.0% due to net cost deflation which was partially offset by unfavorable sales performance, increased overhead investment, and increased brand-building investment.

Latin America

Year-to-date internal net sales for Latin America improved by 2.9% as strong price realization has more than offset sales declines in the first quarter resulting from the volume elasticity impact of the introduction of a new food tax in Mexico.

Year-to-date underlying internal operating profit in Latin America improved 11.2% due to favorable sales performance which was partially offset by net cost inflation and increased overhead investment.

Asia Pacific

Year-to-date internal net sales for Asia Pacific improved by 1.3% due to sales growth in most markets. This was partially offset by weakness in the Australian cereal category and our performance in South Africa. In South Africa, we conducted construction work in the second quarter and it took longer to bring the plant back on line than expected. This impacted our ability to supply the market during the second quarter. It is important to note that the plant is producing once again.

Year-to-date underlying internal operating profit in Asia Pacific declined 25.6% due to the weakness in the Australian cereal category, our performance in South Africa, increased brand-building investment, and net cost inflation.

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Margin performance

Margin performance for the quarter and year-to-date periods of 2014 versus 2013 is as follows:

Quarter	**2014**	2013	Change vs. prior year (pts.)
Reported gross margin (a)	**35.5%**	39.0%	**(3.5)**
Mark-to-market (COGS) (b)	**(1.9)%**	%	**(1.9)**
Restructuring and cost reduction activities (COGS) (c)	**(1.7)%**	(0.3)%	**(1.4)**
Underlying gross margin (d)	**39.1%**	39.3%	**(0.2)**
Reported SGA%	**(25.5)%**	(25.4)%	**(0.1)**
Mark-to-market (SGA) (b)	**%**	%	
Restructuring and cost reduction activities (SGA) (c)	**(0.8)%**	(0.4)%	**(0.4)**
Underlying SGA% (d)	**(24.7)%**	(25.0)%	**0.3**
Reported operating margin	**10.0%**	13.6%	**(3.6)**
Mark-to-market (b)	**(1.9)%**	%	**(1.9)**
Restructuring and cost reduction activities (c)	**(2.5)%**	(0.7)%	**(1.8)**
Underlying operating margin (d)	**14.4%**	14.3%	**0.1**

Year-to-date	**2014**	2013	
Reported gross margin (a)	**38.0%**	38.3%	**(0.3)**
Mark-to-market (COGS) (b)	**0.4%**	(0.5)%	**0.9**
Restructuring and cost reduction activities (COGS) (c)	**(1.2)%**	(0.2)%	**(1.0)**
Underlying gross margin (d)	**38.8%**	39.0%	**(0.2)**
Reported SGA%	**(24.9)%**	(24.3)%	**(0.6)**
Mark-to-market (SGA) (b)	**%**	%	
Restructuring and cost reduction activities (SGA) (c)	**(0.8)%**	(0.2)%	**(0.6)**
Underlying SGA% (d)	**(24.1)%**	(24.1)%	
Reported operating margin	**13.1%**	14.0%	**(0.9)**
Mark-to-market (b)	**0.4%**	(0.5)%	**0.9**
Restructuring and cost reduction activities (c)	**(2.0)%**	(0.4)%	**(1.6)**
Underlying operating margin (d)	14.7%	14.9%	(0.2)

(a) Reported gross margin as a percentage of net sales. Gross margin is equal to net sales less cost of goods sold.
(b)

Includes mark-to-market adjustments for pension plans and commodity contracts as reflected in cost of goods sold. Actuarial gains/losses for pension plans are recognized in the year they occur. A portion of these mark-to-market adjustments were capitalized as inventoriable cost at the end of 2013 and 2012. These amounts have been recognized in the first quarter of 2014 and 2013, respectively. During the third quarter of 2014, we remeasured the benefit obligation for an impacted other nonpension postretirement plan. The remeasurement resulted in a mark-to-market loss of $7 million primarily due to a lower discount rate. Mark-to-market adjustments for commodities reflect the changes in the fair value of contracts for the difference between contract and market prices for the underlying commodities. The resulting gains/losses are recognized in the quarter they occur.

(c) Costs incurred related primarily to the execution of Project K, a global four-year efficiency and effectiveness program. The focus of the program will be to strengthen existing businesses in core markets, increase growth in developing and emerging markets, and drive an increased level of value-added innovation. The program is expected to provide a number of benefits, including an optimized supply chain infrastructure, the implementation of global business services, and a new global focus on categories. The 2013 periods presented have been recast to exclude all restructuring and cost reduction activities from underlying and comparable results. Previously, only costs associated with Project K were excluded from underlying and comparable results.

(d) Underlying gross margin, underlying SGA%, and underlying operating margin are non-GAAP measures that exclude the impact of pension and commodity mark-to-market adjustments and restructuring and cost reduction activities. We believe the use of such non-GAAP measures provides increased transparency and assists in understanding our underlying operating performance.

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Underlying gross margin for the quarter declined 20 basis points due to unfavorable product mix, lower production volume resulting from soft sales performance, and increased integration costs, partially offset by net cost deflation. Underlying SG&A % improved 30 basis points as a result of decreased advertising investment, reduced integration costs and continued discipline in overhead control.

On a year-to-date basis, underlying gross margin declined 20 basis points due to lower production volume resulting from soft sales performance and increased integration costs. Underlying SG&A % was flat as reduced integration costs and continued discipline in overhead control were offset by advertising and consumer promotion investment.

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Our underlying gross profit, underlying SG&A, and underlying operating profit measures are reconciled to the most comparable GAAP measure as follows:

Quarter (dollars in millions)	**2014**	2013
Reported gross profit (a)	**$ 1,292**	$ 1,450
Mark-to-market (COGS) (b)	**(66)**	2
Restructuring and cost reduction activities (c)	**(64)**	(12)
Underlying gross profit (d)	**$ 1,422**	$ 1,460
Reported SGA	**$ 927**	$ 946
Mark-to-market (SGA) (b)		
Restructuring and cost reduction activities (c)	**(28)**	(17)
Underlying SGA (d)	**$ 899**	$ 929
Reported operating profit	**$ 365**	$ 504
Mark-to-market (b)	**(66)**	2
Restructuring and cost reduction activities (c)	**(92)**	(29)
Underlying operating profit (d)	**$ 523**	$ 531

Year-to-date (dollars in millions)	**2014**	2013
Reported gross profit (a)	**$ 4,207**	$ 4,320
Mark-to-market (COGS) (b)	**38**	(59)
Restructuring and cost reduction activities (c)	**(120)**	(23)
Underlying gross profit (d)	**$ 4,289**	$ 4,402
Reported SGA	**$ 2,761**	$ 2,743
Mark-to-market (SGA) (b)		
Restructuring and cost reduction activities (c)	**(104)**	(26)
Underlying SGA (d)	**$ 2,657**	$ 2,717
Reported operating profit	**$ 1,446**	$ 1,577
Mark-to-market (b)	**38**	(59)
Restructuring and cost reduction activities (c)	**(224)**	(49)
Underlying operating profit (d)	**$ 1,632**	$ 1,685

(a) Gross profit is equal to net sales less cost of goods sold.

(b) Includes mark-to-market adjustments for pension plans and commodity contracts as reflected in cost of goods sold. Actuarial gains/losses for pension plans are recognized in the year they occur. A portion of these mark-to-market adjustments were capitalized as inventoriable cost at the end of 2013 and 2012. These amounts have been recognized in the first quarter of 2014 and 2013, respectively. During the third quarter of 2014, we remeasured the benefit obligation for an impacted other nonpension postretirement plan. The remeasurement resulted in a mark-to-market loss of $7 million primarily due to a lower discount rate. Mark-to-market adjustments for commodities reflect the changes in the fair value of contracts for the difference between contract and market prices for the underlying commodities. The resulting gains/losses are recognized in the quarter they occur.

(c) Costs incurred related primarily to the execution of Project K, a global four-year efficiency and effectiveness program. The focus of the program will be to strengthen existing businesses in core markets, increase growth in developing and emerging markets, and drive an increased level of value-added innovation. The program is expected to provide a number of benefits, including an optimized supply chain infrastructure, the implementation of global business services, and a new global focus on categories. The 2013 periods presented have been recast to exclude all restructuring and cost reduction activities from underlying and comparable results. Previously, only costs associated with Project K were excluded from underlying and comparable results.

(d) Underlying gross profit, underlying SGA, and underlying operating profit are non-GAAP measures that exclude the impact of pension and commodity mark-to-market adjustments and costs related to restructuring and cost reduction activities. We believe the use of these non-GAAP measures provide increased transparency and assist in understanding underlying operating performance.

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Foreign currency translation

The reporting currency for our financial statements is the U.S. dollar. Certain of our assets, liabilities, expenses and revenues are denominated in currencies other than the U.S. dollar, including the euro, British pound, Australian dollar, Canadian dollar, Mexican peso, Venezuelan bolivar fuerte and Russian ruble. To prepare our consolidated financial statements, we must translate those assets, liabilities, expenses and revenues into U.S. dollars at the applicable exchange rates. As a result, increases and decreases in the value of the U.S. dollar against these other currencies will affect the value of these items in our consolidated financial statements, even if their value has not changed in their original currency. This could have a significant impact on our results if such increase or decrease in the value of the U.S. dollar is substantial.

Restructuring and cost reduction activities

We view continued spending on restructuring and cost reduction activities as part of our ongoing operating principles to provide greater visibility in achieving our long-term profit growth targets. Initiatives undertaken are currently expected to recover cash implementation costs within a five-year period of completion. Upon completion (or as each major stage is completed in the case of multi-year programs), the project begins to deliver cash savings and/or reduced depreciation.

We have initiated a number of restructuring and cost reduction activities. The most recent and largest program that is currently active is Project K, a four-year efficiency and effectiveness program announced in November 2013. The program is expected to generate a significant amount of savings that will be invested in key strategic areas of focus for the business. We expect that this investment will drive future growth in revenues, gross margin, operating profit, and cash flow.

The focus of the program will be to strengthen existing businesses in core markets, increase growth in developing and emerging markets, and drive an increased level of value-added innovation. The program is expected to provide a number of benefits, including an optimized supply chain infrastructure, the implementation of global business services, and a new global focus on categories.

During the quarter ended September 27, 2014, the Company recorded total charges of $92 million across all restructuring and cost reduction activities. The charges were comprised of $64 million being recorded in cost of goods sold (COGS) and $28 million recorded in selling, general and administrative (SGA) expense. During the year-to-date period ended September 27, 2014, the Company recorded total charges of $224 million across all restructuring and cost reduction activities. The charges were comprised of $120 million being recorded in COGS and $104 million recorded in SGA expense.

During the quarter ended September 28, 2013 the Company recorded total charges of $29 million across all restructuring and cost reduction activities. The charges were comprised of $12 million being recorded in COGS and $17 million recorded in SGA expense. During the year-to-date period ended September 28, 2013 the Company recorded total charges of $49 million across all restructuring and cost reduction activities. The charges were comprised of $23 million being recorded in COGS and $26 million recorded in SGA expense.

The tables below provide the details for charges across all restructuring and cost reduction activities incurred during the quarters and year-to-date periods ended September 27, 2014 and September 28, 2013 and program costs to date for programs currently active as of September 27, 2014.

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(millions)	Quarter ended September 27, 2014	Quarter ended September 28, 2013	Year-to-date period ended September 27, 2014	Year-to-date period ended September 28, 2013	Program costs to date September 27, 2014
Employee related costs	**$ 22**	$ 12	**$ 74**	$ 17	**$ 183**
Asset related costs	**6**		**16**	5	**25**
Asset Impairment	**21**		**21**		**87**
Other costs	**43**	17	**113**	27	**163**
Total	**$ 92**	$ 29	**$ 224**	$ 49	**$ 458**

(millions)	Quarter ended September 27, 2014	Quarter ended September 28, 2013	Year-to-date period ended September 27, 2014	Year-to-date period ended September 28, 2013	Program costs to date September 27, 2014
U.S. Morning Foods	**$ 15**	$ 7	**$ 41**	$ 12	**$ 151**
U.S. Snacks	**32**	4	**42**	10	**69**
U.S. Specialty	**1**	1	**2**	3	**7**
North America Other	**2**		**11**	1	**23**
Europe	**23**	6	**63**	6	**82**
Latin America	**1**	3	**6**	3	**13**
Asia Pacific	**11**	1	**22**	7	**46**
Corporate	**7**	7	**37**	7	**67**
Total	**$ 92**	$ 29	**$ 224**	$ 49	**$ 458**

For the quarter and year-to-date periods ended September 27, 2014 and September 28, 2013 employee related costs consist primarily of severance benefits, asset related costs consist primarily of accelerated depreciation, and other costs consist primarily of third-party incremental costs related to the development and implementation of global business capabilities.

We currently anticipate that Project K will result in total pre-tax charges, once all phases are approved and implemented, of $1.2 to $1.4 billion, with after-tax cash costs, including incremental capital expenditures, estimated to be $900 million to $1.1 billion. Cash expenditures, after tax and including incremental capital, of approximately $182 million were incurred in the year-to-date period ended September 27, 2014. Total cash expenditures, as defined, are expected to be approximately $300 to $400 million in 2014 and the balance of $600 to $700 million thereafter. We currently expect the charges will consist of asset-related costs totaling $450 to $500 million which will consist primarily of asset impairments, accelerated depreciation and other exit-related costs; employee-related costs totaling $425 to $475 million which will include severance, pension and other termination benefits; and other costs totaling $325 to $425 million which will consist primarily of charges related to the design and implementation of global business capabilities. A significant portion of other costs are the result of the implementation of global business service centers which are intended to simplify and standardize business support processes. Costs incurred to date related to Project K through September 27, 2014 totaled $419 million.

We currently expect that total pre-tax charges will impact reportable segments as follows: U.S. Morning Foods (approximately 17%), U.S. Snacks (approximately 10%), U.S. Specialty (approximately 1%), North America Other (approximately 3%), Europe (approximately 12%), Latin America (approximately 3%), Asia-Pacific (approximately 6%), and Corporate (approximately 48%). A majority of the costs impacting Corporate relate to additional initiatives to be executed after 2014 that are currently not fully defined. As the development of these initiatives is completed, we will update its estimated costs by reportable segment as needed.

We expect annual cost savings generated from Project K will be approximately $425 to $475 million by 2018, with approximately two-thirds of the cost savings to be realized in cost of goods sold. We realized $15 million of savings in 2013 and expect $60 to $70 million of savings in 2014, approximately 40% of which will come from cost of goods sold. Cost savings will be reinvested into the business through additional investments in advertising, in-store execution, and in the design and quality of our products. We will also invest in production capacity in developing and emerging markets, and in global category teams.

As a result of Project K, we anticipate that capital spending will be impacted at least through the end of fiscal year 2015. Our current business model assumes capital spending to be approximately 3-4% of net sales annually. Through the end of fiscal year 2015, capital spending is expected to be approximately 4-5% as a result of Project K activities.

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Due to the difference in timing between expected cash costs for the project and expected future cash savings, we anticipate funding the project through a combination of cash on hand and short-term debt.

We also expect that the project will have an impact on our consolidated effective income tax rate during the execution of the project due to the timing of charges being taken in different tax jurisdictions. The impact of this project on our consolidated effective income tax rate will be excluded from the underlying income tax rate that will be disclosed on a quarterly basis.

At September 27, 2014 reserves for all restructuring and cost reduction activities are reflected in the table below. A substantial portion of these reserves will be paid out in 2014 and 2015 related to severance payments and other costs.

(millions)	Employee Related Costs	Asset Impairment	Asset Related Costs	Other Costs	**Total**
Liability as of December 28, 2013	$ 66	$	$	$ 12	$ 78
2014 restructuring charges	74	21	16	113	224
Cash payments	(40)		(7)	(116)	(163)
Non-cash charges and other	12	(21)	(9)		(18)
Liability as of September 27, 2014	**$ 112**	**$**	**$**	**$ 9**	**$ 121**

Interest expense

For the quarter and year-to-date period ended September 27, 2014, interest expense was $54 million and $156 million, respectively, as compared to the quarter and year-to-date period ended September 28, 2013 with interest expense of $56 million and $177 million, respectively. The decrease in interest expense from the prior year is due primarily to the repayment of debt replaced by a combination of lower yield debt and commercial paper.

For the full year 2014, we expect gross interest expense to be approximately $210 million, compared to 2013 s full year interest expense of $235 million.

Income taxes

Our reported effective tax rates for the quarters ended September 27, 2014 and September 28, 2013 were 27.7% and 27.4%, respectively. Underlying effective tax rates for the quarters ended September 27, 2014 and September 28, 2013 were 28.5% and 27.7%, respectively. Refer to Note 8 within Notes to Consolidated Financial Statements for further information.

For the full year 2014, we currently expect the underlying reported effective income tax rate to be approximately 29%. Fluctuations in foreign currency exchange rates could impact the expected effective income tax rate as it is dependent upon U.S. dollar earnings of foreign subsidiaries doing business in various countries with differing statutory rates. Additionally, the rate could be impacted if pending uncertain tax matters, including tax positions that could be affected by planning initiatives, are resolved more or less favorably than we currently expect.

The following table sets forth a summary of our cash flows:

	Year-to-date period ended	
(millions)	**September 27, 2014**	September 28, 2013
Net cash provided by (used in):		
Operating activities	**$ 1,177**	$ 1,389
Investing activities	**(348)**	(364)
Financing activities	**(688)**	(982)

Effect of exchange rates on cash and cash equivalents		**12**		(24)
Net increase in cash and cash equivalents	**$**	**153**	$	19

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Liquidity and capital resources

Our principal source of liquidity is operating cash flows supplemented by borrowings for major acquisitions and other significant transactions. Our cash-generating capability is one of our fundamental strengths and provides us with substantial financial flexibility in meeting operating and investing needs.

Operating activities

The principal source of our operating cash flow is net earnings, meaning cash receipts from the sale of our products, net of costs to manufacture and market our products.

Net cash provided by our operating activities for the year-to-date period ended September 27, 2014 amounted to $1,177 million, a decrease of $212 million compared to the same period in 2013. The decrease compared to the prior year is primarily due to an unfavorable year-over-year variance in after-tax Project K cash payments and other working capital items. Net cash provided by operating activities for the year-to-date periods ended September 27, 2014 and September 28, 2013 were negatively impacted by $118 million and $26 million of after-tax Project K cash payments, respectively.

Our cash conversion cycle (defined as days of inventory, excluding inventoriable mark-to-market pensions and commodity costs, and trade receivables outstanding less days of trade payables outstanding, based on a trailing 12 month average) is relatively short, equating to approximately 30 days for each of the 12 month periods ended September 27, 2014 and September 28, 2013. Compared with the 12 month period ended September 28, 2013, the 2014 cash conversion cycle was relatively consistent for accounts payable. An unfavorable increase in accounts receivable was offset by a favorable decrease in inventory days outstanding.

Our pension and other postretirement benefit plan contributions amounted to $44 million and $42 million for the year-to-date periods ended September 27, 2014 and September 28, 2013, respectively. For the full year 2014, we currently expect that our contributions to pension and other postretirement plans will total approximately $57 million. Plan funding strategies may be modified in response to our evaluation of tax deductibility, market conditions and competing investment alternatives.

We measure cash flow as net cash provided by operating activities reduced by expenditures for property additions. We use this non-GAAP financial measure of cash flow to focus management and investors on the amount of cash available for debt repayment, dividend distributions, acquisition opportunities, and share repurchases. Our cash flow metric is reconciled to the most comparable GAAP measure, as follows:

	Year-to-date period ended		*Change versus*
(millions)	**September 27, 2014**	September 28, 2013	*prior year*
Net cash provided by operating activities	**$ 1,177**	$ 1,389	**(15.3)%**
Additions to properties	**(355)**	(363)	
Cash flow	**$ 822**	$ 1,026	**(19.9)%**

For the full-year 2014, we are projecting cash flow (as defined) to be approximately $1.0 billion to $1.1 billion.

Investing activities

Our net cash used in investing activities, primarily consisting of additions to properties, for the year-to-date period ended September 27, 2014 amounted to $348 million compared to $364 million in the same period of 2013. For the full-year 2014, we project capital spending to be between 4% and 5% of net sales.

Financing activities

Our net cash used in financing activities for the year-to-date period ended September 27, 2014 amounted to $688 million compared to $982 million in the same period of 2013.

In March 2014, we retired an aggregate of $681 million of our 2020, 2022 and 2023 debt through a tender offer, which was primarily funded by commercial paper. In connection with the debt redemption, we incurred $1 million of interest expense, offset by $8 million of accelerated gains on interest rate hedges previously recorded in accumulated other comprehensive income, and recorded $5 million in Other Income, Expense (net), related to acceleration of deferred fees on the redeemed debt and fees related to the tender offer. These charges were included in cash flows for operating activities.

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In May 2014, we issued Cdn. $300 million of long-term debt using the proceeds to retire Cdn. $300 million of long-term debt at maturity.

In May 2014, we issued 500 million of long-term debt using the proceeds for general corporate purposes, which included repayment of a portion of our commercial paper.

In February 2013, we issued long-term debt for net proceeds of approximately $645 million and in March 2013, retired $749 million of long-term debt at maturity.

In December 2012, our board of directors approved a $300 million share repurchase program for 2013. In April 2013, the board of directors approved a $1 billion share repurchase program expiring in April 2014. In February 2014, the board of directors approved a new authorization to repurchase up to $1.5 billion in shares through December 2015. This authorization supersedes the April 2013 authorization and is intended to allow us to repurchase shares for general corporate purposes and to offset issuances for employee benefit programs. Actual repurchases could be different from our current expectations, as influenced by factors such as the impact of changes in our stock price and other competing priorities. In May 2013, we entered into an Accelerated Share Repurchase (ASR) Agreement with a financial institution counterparty and paid $355 million for the purchase of shares during the term of the Agreement which extended through August 2013. The total number of shares delivered upon settlement of the ASR was based upon the volume weighted average price of our company s stock over the term of the Agreement. Total purchases in 2014 and 2013, including shares initially delivered under the ASR were 11 million shares for $690 million and 9 million shares for $544 million, respectively.

We paid cash dividends of $506 million in the year-to-date period ended September 27, 2014 compared to $486 million during the same period in 2013. The increase in dividends paid reflects our third quarter 2013 increase in the quarterly dividend to $.46 per common share, from the previous $.44 per common share. In October 2014, the board of directors declared a dividend of $.49 per common share, payable on December 15, 2014 to shareholders of record at the close of business on December 1, 2014. The dividend is consistent with our current plan to maintain our dividend pay-out between 40% and 50% of underlying net income.

In February 2014, we entered into an unsecured five year credit agreement expiring in 2019, which allows us to borrow, in a revolving credit basis, up to $2.0 billion. This agreement replaced our unsecured four year credit agreement, which would have expired in March 2015.

We are evaluating alternatives to refinance our existing notes payable on a longer-term basis.

We are in compliance with all debt covenants. We continue to believe that we will be able to meet our interest and principal repayment obligations and maintain our debt covenants for the foreseeable future. We expect our access to public debt and commercial paper markets, along with operating cash flows, will be adequate to meet future operating, investing and financing needs, including the pursuit of selected acquisitions.

Accounting standards to be adopted in future periods

In May 2014, the Financial Accounting Standards Board (FASB) issued an Accounting Standards Update (ASU) which provides guidance for accounting for revenue from contracts with customers. The core principle of this ASU is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled in exchange for those goods or services. To achieve that core principle, an entity would be required to apply the following five steps: 1) identify the contract(s) with a customer; 2) identify the performance obligations in the contract; 3) determine the transaction price; 4) allocate the transaction price to the performance obligations in the contract and 5) recognize revenue when (or as) the entity satisfies a performance obligation. The ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early adoption is not permitted. Entities will have the option to apply the final standard retrospectively or use a modified retrospective method, recognizing the cumulative effect of the ASU in retained earnings at the date of initial application. An entity will not restate prior periods if it uses the modified retrospective method, but will be required to disclose the amount by which each financial statement line item is affected in the current reporting period by the application of the ASU as compared to the guidance in effect prior to the change, as well as reasons for significant changes. We will adopt the updated standard in the first quarter of 2017. We are currently evaluating the impact that implementing this ASU will have on our financial statements and disclosures, as well as whether we will use the retrospective or modified retrospective method of adoption.

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Forward-looking statements

This Report contains forward-looking statements with projections concerning, among other things, the Company s global growth and efficiency program (Project K), the integration of the *Pringles*® business, our strategy, financial principles, and plans; initiatives, improvements and growth; sales, gross margins, advertising, promotion, merchandising, brand building, operating profit, and earnings per share; innovation; investments; capital expenditures; costs, charges, rates of return, asset write-offs and expenditures and costs related to productivity or efficiency initiatives; workforce reductions, savings, the impact of accounting changes and significant accounting estimates; our ability to meet interest and debt principal repayment obligations; minimum contractual obligations; future common stock repurchases or debt reduction; effective income tax rate; cash flow and core working capital improvements; interest expense; commodity, and energy prices; and employee benefit plan costs and funding. Forward-looking statements include predictions of future results or activities and may contain the words expects, believes, will, can, anticipates, projects, should, estimates, implies, forecasted, or words or phrases of similar meaning. For example, forward-looking statements are found in Item 1 and in several sections of Management s Discussion and Analysis. Our actual results or activities may differ materially from these predictions. Our future results could be affected by a variety of factors, including:

the ability to implement Project K as planned, whether the expected amount of costs associated with Project K will differ from forecasts, whether the Company will be able to realize the anticipated benefits from Project K in the amounts and times expected;

the ability to realize the anticipated benefits and synergies from the Pringles acquisition in the amounts and at the times expected;

the impact of competitive conditions;

the effectiveness of pricing, advertising, and promotional programs;

the success of innovation, renovation and new product introductions;

the recoverability of the carrying value of goodwill and other intangibles;

the success of productivity improvements and business transitions;

commodity and energy prices;

labor costs;

disruptions or inefficiencies in supply chain;

the availability of and interest rates on short-term and long-term financing;

actual market performance of benefit plan trust investments;

the levels of spending on systems initiatives, properties, business opportunities, integration of acquired businesses, and other general and administrative costs;

changes in consumer behavior and preferences;

the effect of U.S. and foreign economic conditions on items such as interest rates, statutory tax rates, currency conversion and availability;

legal and regulatory factors including changes in food safety, advertising and labeling laws and regulations;

the ultimate impact of product recalls;

business disruption or other losses from natural disasters, war, terrorist acts, or political unrest; and,

the risks and uncertainties described herein under Part II, Item 1A.

Forward-looking statements speak only as of the date they were made, and we undertake no obligation to publicly update them.

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Item 3. Quantitative and Qualitative Disclosures about Market Risk

Our Company is exposed to certain market risks, which exist as a part of our ongoing business operations. We use derivative financial and commodity instruments, where appropriate, to manage these risks. Refer to Note 9 within Notes to Consolidated Financial Statements for further information on our derivative financial and commodity instruments.

Refer to disclosures contained within Item 7A of our 2013 Annual Report on Form 10-K. Other than changes noted here, there have been no material changes in the Company s market risk as of September 27, 2014.

In February 2014, we entered into forward starting interest swaps with notional amounts totaling $690 million, as a hedge against interest rate volatility associated with a forecasted issuance of fixed rate debt to fund the repayment of commercial paper and for general corporate purposes. These swaps were designated as cash flow hedges. These forward starting interest swaps were settled in May 2014 upon the related issuance of fixed rate debt. A resulting loss of $17 million was recorded in accumulated other comprehensive income (loss) and will be amortized as interest expense over the life of the related fixed rate debt. Refer to Note 5 within Notes to Consolidated Financial Statements for further information related to the fixed rate debt issuance.

In June 2014, we entered into forward starting interest swaps with notional amounts totaling 500 million (approximately $639 million USD as of September 27, 2014), as a hedge against interest rate volatility associated with a forecasted issuance of fixed rate debt to be used for general corporate purposes. These swaps were designated as cash flow hedges.

The total notional amount of interest rate swaps at September 27, 2014 was $3.0 billion, with a fair value of the related liability of $63 million. The total notional amount of interest rate swaps at December 28, 2013 was $2.4 billion, with a fair value of the related liability of $59 million. Assuming average variable rate debt levels during the year, a one percentage point increase in interest rates would have increased annual interest expense by approximately $34 million at September 27, 2014 and $35 million at December 28, 2013.

Venezuela was designated as a highly inflationary economy as of the beginning of our 2010 fiscal year. Gains and losses resulting from the translation of the financial statements of subsidiaries operating in highly inflationary economies are recorded in earnings. In February 2013, the Venezuelan government announced a 46.5% devaluation of the official CADIVI (now named CENCOEX) exchange rate from 4.3 bolivars to 6.3 bolivars to the U.S. dollar. Additionally, the Transaction System for Foreign Currency Denominated Securities (SITME), used between May 2010 and January 2013 to translate our Venezuelan subsidiary s financial statements to U.S. dollars, was eliminated. Accordingly, in February 2013 we began using the CENCOEX exchange rate to translate our Venezuelan subsidiary s financial statements to U.S. dollars and in the year-to-date period ended September 28, 2013, we recognized a $14 million charge as a result of the devaluation of the CENCOEX exchange rate. The CENCOEX exchange is restricted to some raw materials, finished goods, and machinery for sectors considered as national priorities, which is primarily food and medicines.

In March, 2013, the Venezuelan government announced a new auction-based currency transaction program referred to as SICAD1. SICAD1 allows entities in specific sectors to bid for U.S. dollars to be used for specified import transactions, with the minimum exchange rate to be offered being 6.3 bolivars to the U.S. dollar. As of September 27, 2014, the published SICAD1 rate offered was 12.0 bolivars to the U.S. dollar and availability of U.S. dollars at either exchange rate continues to be limited.

In January, 2014, the Venezuelan government announced the expansion of the SICAD1 auction program to prospective dividends and royalties and new profit margin controls. As our Venezuelan subsidiary declares dividends or pays royalties in the future, based on the availability of U.S. dollars exchanged under the SICAD1 program, the realized exchange losses on payments made in U.S. dollars would be recognized in earnings. On profit level controls, we continue to evaluate the announced measures and will look to protect net revenues and profitability.

In February 2014, the Venezuelan government announced plans to launch a third foreign exchange mechanism, known as SICAD2, which became operational on March 24, 2014. SICAD2 relies on U.S. dollar cash and U.S. dollar denominated bonds offered by the Venezuelan Central Bank, PDVSA (the national oil and gas company) and private companies. The Venezuelan government has indicated that all industry sectors will be able to access SICAD2 and its use will not be restricted as to purpose. As of September 27, 2014, the published SICAD2 rate was 50.0 bolivars to the U.S. dollar.

In light of the current difficult macroeconomic environment in Venezuela, we continue to monitor and actively manage our investment and exposures in Venezuela. Our Venezuelan business does not rely heavily on imports and when items are imported, they are largely exchanged at the CENCOEX rate. As of September 27, 2014, we translated our Venezuelan subsidiary s financial statements to U.S. dollars using the CENCOEX exchange rate. We will continue to monitor local

conditions, our continued ability to obtain U.S. dollars at the CENCOEX exchange rate, and the use, if applicable, of the SICAD1 and SICAD2 mechanisms to determine the appropriate rate for translation. For the year-to-date period ended September 27, 2014, Venezuela represented approximately 2% of total net sales and 3% of total underlying operating profit. For the year-to-date period ended September 28, 2013, Venezuela represented approximately 1% of total net sales and 2% of total underlying operating profit. As of September 27, 2014, our net monetary assets denominated in the Venezuelan bolivar were $100 million in U.S. dollars applying the CENCOEX exchange rate. If the CENCOEX exchange rate were to devalue further or if the currently less favorable SICAD1 exchange rate were extended to apply to a greater portion of our net monetary assets in Venezuela, we could recognize a devaluation charge in earnings. The potential unfavorable fully diluted EPS impact of adopting the SICAD1 exchange rate, at the current rate of 12.0 bolivars to the U.S. dollar, would be approximately $.11 for the revaluation of our net monetary assets denominated in the Venezuelan bolivar at September 27, 2014, and approximately $.01 for the translation of after-tax operating profit during the remainder of 2014. The potential unfavorable fully diluted EPS impact of adopting the SICAD2 exchange rate, at the current rate of 50.0 bolivars to the U.S. dollar, would be approximately $.21 for the revaluation of our net monetary assets denominated in the Venezuelan bolivar at September 27, 2014, and approximately $.01 for the translation of after-tax operating profit during the remainder of 2014. We continue to monitor the currency developments in Venezuela and take protective measures against currency devaluation which may include converting monetary assets into non-monetary assets which we can use in our business.

Item 4. Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our chief executive officer and chief financial officer as appropriate, to allow timely decisions regarding required disclosure under Rules 13a-15(e) and 15d-15(e). Disclosure controls and procedures, no matter how well designed and operated, can provide only reasonable, rather than absolute, assurance of achieving the desired control objectives.

As of September 27, 2014, we carried out an evaluation under the supervision and with the participation of our chief executive officer and our chief financial officer, of the effectiveness of the design and operation of our disclosure controls and procedures. Based on the foregoing, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective at the reasonable assurance level.

During the first quarter of 2012, we initiated the implementation of an upgrade to our existing enterprise resource planning (ERP) system within North America. This implementation has resulted in the modification of certain business processes and internal controls impacting financial reporting. During the implementation, which is expected to be completed in 2014, we have taken the necessary steps to monitor and maintain appropriate internal controls impacting financial reporting. It is anticipated that, upon completion, implementation of this new ERP will enhance internal controls due to increased automation and further integration of related processes.

During the third quarter of 2014, we went live with the first phase of our Global Business Services (GBS) initiative, in conjunction with Project K, which includes the reorganization and relocation of certain financial service processes, internal to the organization. This initiative is expected to continue through 2016 and will impact the design of our control framework. During the transition to GBS, we have put additional controls in place to monitor and maintain appropriate internal controls impacting financial reporting.

There have been no other changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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KELLOGG COMPANY

PART II OTHER INFORMATION

Item 1A. Risk Factors

There have been no material changes in our risk factors from those disclosed in Part I, Item 1A to our Annual Report on Form 10-K for the fiscal year ended December 28, 2013. The risk factors disclosed under those Reports in addition to the other information set forth in this Report, could materially affect our business, financial condition, or results. Additional risks and uncertainties not currently known to us or that we deem to be immaterial could also materially adversely affect our business, financial condition, or results.

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

(c) Issuer Purchases of Equity Securities

(millions, except per share data)

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
Month #1:				
6/29/14-7/26/14		$ 0.00		$ 1,430
Month #2:				
7/27/14-8/23/14	3.0	$ 63.38	3.0	$ 1,238
Month #3:				
8/24/14-9/27/14	2.6	$ 64.54	2.6	$ 1,069
Total	5.6	$ 63.92	5.6	

In February 2014, our board of directors approved a share repurchase program authorizing us to repurchase shares of our common stock amounting to $1.5 billion through December 2015. This authorization supersedes the April 2013 authorization and is intended to allow us to repurchase shares for general corporate purposes and to offset issuances for employee benefit programs.

Item 6. Exhibits

(a) Exhibits:

31.1 Rule 13a-14(e)/15d-14(a) Certification from John A. Bryant

31.2 Rule 13a-14(e)/15d-14(a) Certification from Ronald L. Dissinger

32.1 Section 1350 Certification from John A. Bryant

32.2	Section 1350 Certification from Ronald L. Dissinger
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

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KELLOGG COMPANY

SIGNATURES

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

KELLOGG COMPANY

/s/ R. L. Dissinger
R. L. Dissinger
Principal Financial Officer;

Senior Vice President and Chief Financial

Officer

/s/ M. A. Dangel
M. A. Dangel
Principal Accounting Officer;

Vice President Corporate Controller

Date: November 4, 2014

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KELLOGG COMPANY

EXHIBIT INDEX

Exhibit No.	Description	Electronic (E) Paper (P) Incorp. By Ref. (IBRF)
31.1	Rule 13a-14(e)/15d-14(a) Certification from John A. Bryant	E
31.2	Rule 13a-14(e)/15d-14(a) Certification from Ronald L. Dissinger	E
32.1	Section 1350 Certification from John A. Bryant	E
32.2	Section 1350 Certification from Ronald L. Dissinger	E
101.INS	XBRL Instance Document	E
101.SCH	XBRL Taxonomy Extension Schema Document	E
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	E
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	E
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	E
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	E

10pt;">

—

—

Other financing activities

2,132

—

(303

)

—

1,829

Net cash provided by (used in) financing activities

166,516

319,300

(23,912
)

—

461,904

Net increase (decrease) in cash and cash equivalents

221

23,582

(10,159
)

—

13,644

Cash and cash equivalents at beginning of period

6

15,067

15,110

—

30,183

Cash and cash equivalents at end of period

$
227

$
38,649

$
4,951

$
—

$
43,827

32

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

Condensed Consolidated Statement of Cash Flows
Nine Months Ended September 30, 2014
(In thousands)

	Parent	Guarantor Subsidiaries	Non–Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by operating activities	$1,915	$220,447	$29,633	$—	$251,995
Cash flows from investing activities:					
Additions to oil and natural gas properties	—	(307,144)	(5,275)	—	(312,419)
Acquisition of leasehold interests	—	(840,482)	—	—	(840,482)
Acquisition of mineral interests	—	—	(57,688)	—	(57,688)
Purchase of other property and equipment	—	(43,215)	—	—	(43,215)
Cost method investment	—	—	(33,851)	—	(33,851)
Intercompany transfers	(631,100)	631,100	—	—	—
Other investing activities	—	(1,426)	—	—	(1,426)
Net cash used in investing activities	(631,100)	(561,167)	(96,814)	—	(1,289,081)
Cash flows from financing activities:					
Proceeds from borrowing on credit facility	—	347,900	78,000	—	425,900
Repayment on credit facility	—	(217,900)	(78,000)	—	(295,900)
Proceeds from public offerings	693,886	—	234,546	—	928,432
Distribution to parent	—	—	(148,760)	—	(148,760)
Distribution to subsidiary	148,760	—	—	—	148,760
Intercompany transfers	(217,900)	217,900	—	—	—
Other financing activities	10,431	(825)	(5,863)	—	3,743
Net cash provided by (used in) financing activities	635,177	347,075	79,923	—	1,062,175
Net increase (decrease) in cash and cash equivalents	5,992	6,355	12,742	—	25,089
Cash and cash equivalents at beginning of period	526	14,267	762	—	15,555
Cash and cash equivalents at end of period	$6,518	$20,622	$13,504	$—	$40,644

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

The following discussion and analysis should be read in conjunction with our unaudited consolidated financial statements and notes thereto presented in this report as well as our audited combined consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2014. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs, and expected performance. Actual results and the timing of events may differ materially from those contained in these forward-looking statements due to a number of factors. See "Part II. Item 1A. Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company focused on the acquisition, development, exploration and exploitation of unconventional, onshore oil and natural gas reserves in the Permian Basin in West Texas. Our activities are primarily directed at the Clearfork, Spraberry, Wolfcamp, Cline, Strawn and Atoka formations which we refer to as the Wolfberry play. We intend to grow our reserves and production through development drilling, exploitation and exploration activities on our multi-year inventory of identified potential drilling locations and through acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves. Substantially all of our revenues are generated through the sale of oil, natural gas liquids and natural gas production. Our production was approximately 73% oil, 16% natural gas liquids and 11% natural gas for the three months ended September 30, 2015, and was approximately 75% oil, 14% natural gas liquids and 11% natural gas for the three months ended September 30, 2014. Our production was approximately 74% oil, 15% natural gas liquids and 11% natural gas for the nine months ended September 30, 2015, and was approximately 76% oil, 14% natural gas liquids and 10% natural gas for the nine months ended September 30, 2014. On September 30, 2015, our net acreage position in the Permian Basin was approximately 85,229 net acres.

2015 Highlights

Common stock transactions

In January 2015, we completed an underwritten public offering of 2,012,500 shares of common stock, which included 262,500 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $59.34 per share and we received net proceeds of approximately $119.4 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In May 2015, we 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 underwriters at $72.53 per share and we received net proceeds of approximately $333.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

In August 2015, we completed an underwritten public offering of 2,875,000 shares of common stock, which included 375,000 shares of common stock issued pursuant to an option to purchase additional shares granted to the underwriters. The stock was sold to the underwriters at $68.74 per share and we received net proceeds of approximately $197.6 million from the sale of these shares of common stock, net of offering expenses and underwriting discounts and commissions.

Acquisitions

Since January 1, 2015, we have acquired from unrelated third party sellers an aggregate of approximately 16,034 gross (12,396 net) acres in the Midland Basin, primarily in northwest Howard County, in the Permian Basin, for an aggregate purchase price of approximately $425.5 million, subject to certain adjustments. Approximately 83% of this acreage is held by production. We believe the acreage is prospective for horizontal drilling in the Lower Spraberry, Wolfcamp A and Wolfcamp B horizons, and have identified an aggregate of approximately 232 net potential horizontal drilling locations in these horizons based on 660 foot spacing between wells. We currently estimate that approximately 42% of the potential horizontal locations will have approximately 10,000 foot laterals, which can provide higher rates of return and capital efficiency than shorter laterals. The average lateral length for these potential horizontal locations is estimated to be approximately 8,357 feet. We also believe that additional development potential may exist in the Middle Spraberry horizon. Salt water disposal infrastructure is already in place on the acreage in Northwest Howard County, and the acquisitions include 3-D seismic data that can be used to geosteer the drilling of horizontal wells. On July 9, 2015, we completed the sale of an approximate average 1.5% overriding royalty interest in certain of our acreage primarily located in Howard County, Texas to the Partnership for $31.1 million.

Operating Results Overview

During the three months ended September 30, 2015, our average daily production was approximately 34,082 BOE/d, consisting of 24,956 Bbls/d of oil, 23,068 Mcf/d of natural gas and 5,281 Bbls/d of natural gas liquids, an increase of 13,446 BOE/d, or 65%, from average daily production of 20,636 BOE/d for the three months ended September 30, 2014, consisting of 15,503 Bbls/d of oil, 13,058 Mcf/d of natural gas and 2,957 Bbls/d of natural gas liquids.

During the nine months ended September 30, 2015, our average daily production was approximately 31,576 BOE/d, consisting of 23,589 Bbls/d of oil, 20,235 Mcf/d of natural gas and 4,615 Bbls/d of natural gas liquids, an increase of 14,208 BOE/d, or 81.8%, from average daily production of 17,368 BOE/d for the nine months ended September 30, 2014, consisting of 13,176 Bbls/d of oil, 10,619 Mcf/d of natural gas and 2,422 Bbls/d of natural gas liquids.

During the three months ended September 30, 2015, we drilled 21 gross (18 net) horizontal wells and participated in the drilling of six gross (2.6 net) non-operated wells in the Permian Basin. During the nine months ended September 30, 2015, we drilled 47 gross (40 net) horizontal wells and three gross (two net) vertical wells and participated in the drilling of 12 gross (five net) non-operated wells in the Permian Basin.

During the third quarter of 2015, we completed our first operated Wolfcamp A well as part of a triple stacked lateral that included a Lower Spraberry and Wolfcamp B. The Trailand A Unit 3906A has a 7,297 foot lateral and was completed with 33 frac stages. It achieved an average peak 30-day 2-stream initial production rate of 1,034 BOE/d (90% oil) on electric submersible pump when normalized to a 7,500 foot lateral. Initial performance indicates that this well is tracking a 750 to 850 MBOE type curve. The Lower Spraberry and Wolfcamp B completions appear consistent with our Ryder Scott type curves for Spanish Trail. We also completed our first operated Middle Spraberry well during the third quarter of 2015. The ST W 705MS has a lateral length of 7,503 feet and was completed with 32 stages. Its peak 30-hour 2-stream initial production rate is 851 BOE/d (91% oil) on electric submersible pump. During the third quarter of 2015, we began drilling our first three-well pad in Glasscock County, which targeted the Lower Spraberry, Wolfcamp A and Wolfcamp B formations. We intend to complete these wells later this year and are currently drilling another pad in the county that targets the Wolfcamp A and Wolfcamp B. We intend to begin drilling a three-well pad in Howard County at the end of the year. This pad will target the Lower Spraberry, Wolfcamp A and Wolfcamp B. We are drilling our first operated four-well stacked pad in southwest Martin County that targets the Middle Spraberry, Lower Spraberry, Wolfcamp A and Wolfcamp B.

As a result of the significant decline in prices from over $91.00 per Bbl in September 2014 to a range of prices between $38.00 per Bbl and $62.00 per Bbl in 2015, we recorded non-cash ceiling test impairments for the three and nine months ended September 30, 2015 of $273.7 million and $597.2 million, respectively.

Oil, natural gas liquids and gas prices have remained low in the fourth quarter of 2015. If prices remain at or below the current low levels, subject to numerous factors and inherent limitations, we will incur an additional non-cash full cost impairment in the fourth quarter of 2015, which will have an adverse effect on our results of operations.

We have received cost concessions from our service providers of 20% to 30% as compared to their peak pricing during 2014. During the third quarter of 2015, we added a fourth and fifth horizontal rig. In October 2015, we released one of our five rigs. We currently intend to run four horizontal rigs during the fourth quarter of 2015 and continue to expect to complete 60 to 70 gross horizontal wells during 2015 for an estimated $400.0 million to $450.0 million of capital expenditures in 2015. We believe that with service cost concessions and increased efficiencies, our high quality assets still provide us with economic wells in a lower cost environment.

Sources of our revenue

Our revenues are derived from the sale of oil and natural gas production, as well as the sale of natural gas liquids that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the three months ended September 30, 2015, our revenues were derived 91% from oil sales, 4% from natural gas liquids sales and 5% from natural gas sales and for the three months ended September 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquids sales and 3% from natural gas sales. For the nine months ended September 30, 2015, our revenues were derived 91% from oil sales, 5% from natural gas liquids sales and 4% from natural gas sales and for the nine months ended September 30, 2014, our revenues were derived 91% from oil sales, 6% from natural gas liquids sales and 3% from natural gas sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold, production mix or commodity prices.

Since our production consists primarily of oil, our revenues are more sensitive to fluctuations in oil prices than they are to fluctuations in natural gas liquids or natural gas prices. Oil, natural gas liquids and natural gas prices have historically been volatile. During 2014, West Texas Intermediate posted prices ranged from $53.45 to $107.95 per Bbl and the Henry Hub spot market price of natural gas ranged from $2.74 to $8.15 per MMBtu. On September 30, 2015, the West Texas Intermediate posted price for crude oil was $45.09 per Bbl and the Henry Hub spot market price of natural gas was $2.47 per MMBtu.

Results of Operations

The following table sets forth selected historical operating data for the periods indicated.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except Bbl, Mcf and BOE amounts)			
Revenues:				
Oil, natural gas and natural gas liquids revenues	$111,946	$139,127	$332,410	$364,135
Operating Expenses:				
Lease operating expenses	22,189	13,805	65,117	32,216
Production and ad valorem taxes	8,966	8,954	25,036	23,350
Gathering and transportation expense	1,688	860	4,343	2,145
Depreciation, depletion and amortization	52,375	45,370	169,148	116,364
Impairment of oil and gas properties	273,737	—	597,188	—
General and administrative	7,526	6,495	23,446	14,986
Asset retirement obligation accretion expense	238	127	588	303
Total expenses	366,719	75,611	884,866	189,364
Income (loss) from operations	(254,773)	63,516	(552,456)	174,771
Net interest expense	(10,633)	(9,846)	(31,404)	(24,090)
Other income	300	48	1,248	108
Other expense	—	(8)	—	(1,416)
Gain (loss) on derivative instruments, net	27,603	14,909	26,834	(577)
Total other income (expense), net	17,270	5,103	(3,322)	(25,975)
Income (loss) before income taxes	(237,503)	68,619	(555,778)	148,796
Income tax provision (benefit)	(81,461)	23,978	(194,823)	52,742
Net income (loss)	(156,042)	44,641	(360,955)	96,054
Less: Net income attributable to noncontrolling interest	739	902	2,264	973
Net income (loss) attributable to Diamondback Energy, Inc.	$(156,781)	$43,739	(363,219)	95,081

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except Bbl, Mcf and BOE amounts)			
Production Data:				
Oil (Bbls)	2,295,940	1,426,271	6,439,699	3,596,983
Natural gas (Mcf)	2,122,248	1,201,296	5,524,138	2,899,097
Natural gas liquids (Bbls)	485,871	272,013	1,259,777	661,160
Combined volumes (BOE)	3,135,519	1,898,500	8,620,166	4,741,326
Daily combined volumes (BOE/d)	34,082	20,636	31,576	17,367
Average Prices:				
Oil (per Bbl)	$44.12	$88.63	$46.87	$92.15
Natural gas (per Mcf)	2.67	3.92	2.61	4.27
Natural gas liquids (per Bbl)	10.22	29.44	12.80	30.72
Combined (per BOE)	35.70	73.28	38.56	76.80
Oil, hedged($/Bbl)[1]	59.59	87.55	63.08	90.42
Average price, hedged($/BOE)[1]	47.03	72.48	50.67	75.49
Average Costs (per BOE)				
Lease operating expense	$7.08	$7.27	$7.55	$6.79
Gathering and transportation expense	0.54	0.45	0.50	0.45
Production and ad valorem taxes	2.86	4.72	2.90	4.92
Production and ad valorem taxes as a % of sales	8.0 %	6.4 %	7.5 %	6.4 %
Depreciation, depletion, and amortization	$16.70	$23.90	$19.62	$24.54
General and administrative	2.40	3.42	2.72	3.16
Interest expense	3.39	5.19	3.64	5.08
Components of general and administrative expense:				
Non-cash stock based compensation, net of capitalized amounts	$4,402	$2,069	$13,659	$5,387
General and administrative cost per BOE excluding non-cash stock based compensation, net of capitalized amounts	$1.00	$2.33	$1.14	$2.03

(1) Hedged prices reflect the effect of our commodity derivative transactions on our average sales prices. Our calculation of such effects include realized gains and losses on cash settlements for commodity derivatives, which we do not designate for hedge accounting.

Comparison of the Three Months Ended September 30, 2015 and 2014

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues decreased by approximately $27.2 million, or 20%, to $111.9 million for the three months ended September 30, 2015 from $139.1 million for the three months ended September 30, 2014. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 13,446 BOE/d to 34,082 BOE/d during the three months ended September 30, 2015 from 20,636 BOE/d during the three months ended September 30, 2014. The total decrease in revenue of approximately $27.2 million is largely attributable to lower average sales prices partially offset by higher oil, natural gas liquids and natural gas production volumes for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 869,669 Bbls of oil, 213,858 Bbls of natural gas liquids and 920,952 Mcf of natural gas for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014. The net dollar effect of the decreases in prices of approximately $114.2 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $87.0 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$(44.51)	2,295,940	$(102,192)
Natural gas liquids	(19.22)	485,871	(9,338)
Natural gas	(1.25)	2,122,248	(2,653)
Total revenues due to change in price			$(114,183)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	869,669	$88.63	$77,096
Natural gas liquids	213,858	29.44	6,296
Natural gas	920,952	3.92	3,610
Total revenues due to change in production volumes			87,002
Total change in revenues			$(27,181)

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Lease Operating Expense. Lease operating expense was $22.2 million ($7.08 per BOE) for the three months ended September 30, 2015, an increase of $8.4 million, or 61%, from $13.8 million ($7.27 per BOE) for the three months ended September 30, 2014. The increase is due to increased drilling activity and acquisitions, which resulted in 236 additional gross producing wells as of September 30, 2015 as compared to September 30, 2014. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes were $9.0 million for both the three months ended September 30, 2015 and 2014. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, among other factors, whereas production taxes are based upon current year commodity prices. During the three months ended September 30, 2015, our production taxes per BOE decreased by $1.86 as compared to the three months ended September 30, 2014, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2015, offset by an increase in ad valorem taxes primarily as a result of increased production, as a result of our acquisitions and drilling activity.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $7.0 million, or 15%, from $45.4 million for the three months ended September 30, 2014 to $52.4 million for the three months ended September 30, 2015.

The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

	Three Months Ended September 30,	
	2015	2014
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$51,996	$45,010
Depreciation of other property and equipment	379	360
Depreciation, depletion and amortization	$52,375	$45,370
Oil and natural gas properties depreciation, depletion and amortization per BOE	$16.58	$23.71
Total depreciation, depletion and amortization per BOE	$16.70	$23.90

The increases in depletion of proved oil and natural gas properties of $7.0 million for the three months ended September 30, 2015 as compared to the three months ended September 30, 2014 resulted primarily from higher total production levels and an increase in net book value on new reserves. On a per BOE basis, depreciation, depletion and amortization decreased primarily due to the impairment of oil and gas properties recorded in the second and third quarter of 2015.

Impairment of Oil and Gas Properties. During the three months ended September 30, 2015, we recorded an impairment of oil and gas properties of $273.7 million as a result of the significant decline in prices from the second quarter of 2015.

General and Administrative Expense. General and administrative expense increased $1.0 million from $6.5 million for the three months ended September 30, 2014 to $7.5 million for the three months ended September 30, 2015. The increase was due to increases in salaries and benefits expense as a result of an increase in workforce and equity based compensation.

Net Interest Expense. Net interest expense for the three months ended September 30, 2015 was $10.6 million as compared to $9.8 million for the three months ended September 30, 2014, an increase of $0.8 million. This increase was due primarily to the higher average level of outstanding borrowings under our credit facility during the three months ended September 30, 2015 as compared to the three months ended September 30, 2014.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned “Gain (loss) on derivative instruments, net.” For the three months ended September 30, 2015 and 2014, we had a cash gain on settlement of derivative instruments of $35.5 million and a cash loss on settlement of derivative instruments of $1.5 million, respectively. For the three months ended September 30, 2015, we had a negative change in the fair value of open derivative instruments of $7.9 million as compared to a positive change in the fair value of open derivative instruments of $16.4 million during the three months ended September 30, 2014.

Income Tax Expense (Benefit). We recorded income tax benefit of $81.5 million for the three months ended September 30, 2015 as compared to $24.0 million for the three months ended September 30, 2014. Our effective tax rate was 34.3% for the three months ended September 30, 2015 as compared to 34.9% for the three months ended September 30, 2014.

Comparison of the Nine Months Ended September 30, 2015 and 2014

Oil, Natural Gas Liquids and Natural Gas Revenues. Our oil, natural gas liquids and natural gas revenues decreased by approximately $31.7 million, or 9%, to $332.4 million for the nine months ended September 30, 2015 from $364.1 million for the nine months ended September 30, 2014. Our revenues are a function of oil, natural gas liquids and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 14,208 BOE/d to 31,576 BOE/d during the nine months ended September 30, 2015 from 17,368 BOE/d during the nine months ended September 30, 2014. The total decrease in revenue of approximately $31.7 million is largely attributable to lower average sales prices partially offset by higher oil, natural gas liquids and natural gas production volumes for the nine months ended September 30, 2015 as compared to the nine months ended September

30, 2014. The increases in production volumes were due to a combination of increased drilling activity and growth through acquisitions. Our production increased by 2,842,716 Bbls of oil, 598,617 Bbls of natural gas liquids and 2,625,041 Mcf of natural gas for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014. The net dollar effect of the decreases in prices of approximately $323.3 million (calculated as the change in period-to-period average prices multiplied by current period production volumes of oil, natural gas liquids and natural gas) and the net dollar effect of the increase in production of approximately $291.6 million (calculated as the increase in period-to-period volumes for oil, natural gas liquids and natural gas multiplied by the period average prices) are shown below.

	Change in prices	Production volumes(1)	Total net dollar effect of change (in thousands)
Effect of changes in price:			
Oil	$(45.28)	6,439,699	$(291,590)
Natural gas liquids	$(17.92)	1,259,777	$(22,575)
Natural gas	$(1.66)	5,524,138	$(9,170)
Total revenues due to change in price			$(323,335)

	Change in production volumes(1)	Prior period average prices	Total net dollar effect of change (in thousands)
Effect of changes in production volumes:			
Oil	2,842,716	$92.15	$262,011
Natural gas liquids	598,617	$30.72	$18,390
Natural gas	2,625,041	$4.27	$11,209
Total revenues due to change in production volumes			$291,610
Total change in revenues			$(31,725)

(1) Production volumes are presented in Bbls for oil and natural gas liquids and Mcf for natural gas

Lease Operating Expense. Lease operating expense was $65.1 million ($7.55 per BOE) for the nine months ended September 30, 2015, an increase of $32.9 million, or 102%, from $32.2 million ($6.79 per BOE) for the nine months ended September 30, 2014. The increase is due to increased drilling activity and acquisitions, which resulted in 236 additional gross producing wells as of September 30, 2015 as compared to September 30, 2014. Upon becoming the operator of wells acquired in our acquisitions, we seek to achieve the efficiencies in those wells that we have established with our existing portfolio of wells.

Production and Ad Valorem Tax Expense. Production and ad valorem taxes increased to $25.0 million for the nine months ended September 30, 2015 from $23.4 million for the nine months ended September 30, 2014. In general, production taxes and ad valorem taxes are directly related to commodity price changes; however, Texas ad valorem taxes are based upon prior year commodity prices, among other factors, whereas production taxes are based upon current year commodity prices. During the nine months ended September 30, 2015, our production taxes per BOE decreased by $2.02 as compared to the nine months ended September 30, 2014, primarily reflecting the impact of lower oil and natural gas prices on production taxes in 2015, offset by an increase in ad valorem taxes primarily as a result of increased production, as a result of our acquisitions and drilling activity.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense increased $52.8 million, or 45%, to $169.1 million for the nine months ended September 30, 2015 from $116.4 million for the nine months ended September 30, 2014.

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The following table provides the components of our depreciation, depletion and amortization expense for the periods presented:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands, except BOE amounts)	
Depletion of proved oil and natural gas properties	$167,928	$115,437
Depreciation of other property and equipment	1,220	927
Depreciation, depletion and amortization	$169,148	$116,364
Oil and natural gas properties depreciation, depletion and amortization per BOE	$19.50	$24.39
Total depreciation, depletion and amortization per BOE	$19.62	$24.54

The increases in depletion of proved oil and natural gas properties of $52.8 million for the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014 resulted primarily from higher total production levels and an increase in net book value on new reserves. On a per BOE basis, depreciation, depletion and amortization decreased primarily due to the impairment of oil and gas properties recorded in the second and third quarter of 2015.

Impairment of Oil and Gas Properties. During the nine months ended September 30, 2015, we recorded an impairment of oil and gas properties of $597.2 million as a result of the significant decline in prices from the third quarter of 2014.

General and Administrative Expense. General and administrative expense increased $8.5 million from $15.0 million for the nine months ended September 30, 2014 to $23.4 million for the nine months ended September 30, 2015. The increase was due to increases in salaries and benefits expense as a result of an increase in workforce and equity-based compensation.

Net Interest Expense. Net interest expense for the nine months ended September 30, 2015 was $31.4 million as compared to $24.1 million for the nine months ended September 30, 2014, an increase of $7.3 million. This increase was due primarily to the higher average level of outstanding borrowings under our credit facility during the nine months ended September 30, 2015 as compared to the nine months ended September 30, 2014.

Derivatives. We are required to recognize all derivative instruments on the balance sheet as either assets or liabilities measured at fair value. We have not designated our derivative instruments as hedges for accounting purposes. As a result, we mark our derivative instruments to fair value and recognize the cash and non-cash changes in fair value on derivative instruments in our combined consolidated statements of operations under the line item captioned "Gain (loss) on derivative instruments, net." For the nine months ended September 30, 2015 and 2014, we had a cash gain on settlement of derivative instruments of $104.4 million and a cash loss on settlement of derivative instruments of $6.2 million, respectively. For the nine months ended September 30, 2015, we had a negative change in the fair value of open derivative instruments of $77.5 million as compared to a positive change in the fair value of open derivative instruments of $5.6 million during the three months ended September 30, 2014.

Income Tax Expense (Benefit). We recorded income tax benefit of $194.8 million for the nine months ended September 30, 2015 as compared to income tax expense of $52.7 million for the nine months ended September 30, 2014. Our effective tax rate was 35.1% for the nine months ended September 30, 2015 as compared to 35.4% for the nine months ended September 30, 2014.

Liquidity and Capital Resources

Our primary sources of liquidity have been proceeds from our public equity offerings, borrowings under our revolving credit facility, proceeds from the issuance of the senior notes and cash flows from operations. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. As we pursue reserves and production growth, we regularly consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us.

Liquidity and Cash Flow

Our cash flows for the nine months ended September 30, 2015 and 2014 are presented below:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Net cash provided by operating activities	$339,604	$251,995
Net cash used in investing activities	(787,864)	(1,289,081)
Net cash provided by financing activities	461,904	1,062,175
Net change in cash	$13,644	$25,089

Operating Activities

Net cash provided by operating activities was $339.6 million for the nine months ended September 30, 2015 as compared to $252.0 million for the nine months ended September 30, 2014. The increase in operating cash flows is primarily the result of the increase in our oil and natural gas revenues due to an 81.8% increase in our net BOE production, partially offset by a 49.8% decrease in our net realized sales prices.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for the oil and natural gas we produce. Prices for these commodities are determined primarily by prevailing market conditions. Regional and worldwide economic activity, weather and other substantially variable factors influence market conditions for these products. These factors are beyond our control and are difficult to predict. See "—Sources of our revenue" above.

Investing Activities

The purchase and development of oil and natural gas properties accounted for the majority of our cash outlays for investing activities. Net cash used in investing activities was $787.9 million and $1,289.1 million during the nine months ended September 30, 2015 and 2014, respectively.

During the nine months ended September 30, 2015, we spent $326.5 million on capital expenditures in conjunction with our infrastructure projects and drilling program, in which we drilled 47 gross (40 net) horizontal wells and three gross (two net) vertical wells and participated in the drilling of 12 gross (five net) non-operated wells in the Permian Basin. We spent an additional $425.5 million on leasehold costs, $1.0 million for the purchase of other property and equipment. In June 2015, we completed acquisitions of oil and natural gas leasehold and mineral interests in Howard County, Texas, in the Permian Basin from unrelated third party sellers for an aggregate purchase price of approximately $425.5 million. Also, during the first nine months of 2015, we completed several smaller acquisitions of oil and natural gas leasehold and mineral interests in the Permian Basin from unrelated third party sellers for an aggregate purchase price of $32.3 million.

During the nine months ended September 30, 2014, we spent $313.9 million on capital expenditures in conjunction with our drilling program in which we drilled 61 gross (49 net) horizontal wells, 31 gross (25 net) vertical wells and participated in the drilling of an additional three gross (one net) non-operated wells. We spent an additional $840.5 million on leasehold acquisitions and $43.2 million for the purchase of other property and equipment. In February 2014, we completed acquisitions of additional oil and natural gas leasehold interests in Martin County, Texas, in the Permian Basin, from unrelated third party sellers for an aggregate purchase price of $289.0 million. On August 25, 2014, we completed an acquisition of surface rights in the Permian Basin from unrelated third party sellers for a purchase price of approximately $41.9 million. On September 9, 2014, we completed the acquisition of oil and natural gas interests from unrelated third party sellers of additional leasehold interests in Midland, Glasscock, Reagan and Upton Counties, Texas in the Permian Basin, for an aggregate purchase price of $524.5 million. We also spent approximately $57.7 million on acquisitions of mineral interests underlying approximately 10,565 gross (3,461) net acres in the Midland and Delaware basins and approximately $33.9 million for a minor equity interest in an entity that owns mineral, overriding royalty, net profits, leasehold and other similar interests.

Our investing activities for the nine months ended September 30, 2015 and 2014 are summarized in the following table:

	Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
Drilling, completion and infrastructure	$(326,469)	$(313,856)
Acquisition of leasehold interests	(425,507)	(840,482)
Acquisition of mineral interests	(32,291)	(57,688)
Purchase of other property and equipment	(992)	(43,215)
Proceeds from sale of property and equipment	97	11
Equity investments	(2,702)	(33,851)
Net cash used in investing activities	$(787,864)	$(1,289,081)

Financing Activities

Net cash provided by financing activities for the nine months ended September 30, 2015 and 2014 was $461.9 million and $1,062.2 million, respectively. During the nine months ended September 30, 2015, the amount provided by financing activities was primarily attributable to the aggregate net proceeds from our January, May and August 2015 equity offerings of $650.7 million partially offset by repayments net of borrowings, of $184.5 million, under our credit facility. The 2014 amount provided by financing activities was primarily attributable to the net proceeds of $208.4 million from our February 2014 equity offering, net proceeds from the Viper Offering of $137.2 million, net proceeds of $485.0 million from our July 2014 equity offering, net proceeds of $95.1 million from the Viper September 2014 equity offering and borrowings, net of repayment of $130.0 million, under our credit facility.

The Company’s Second Amended and Restated Credit Facility

Our second amended and restated credit agreement, dated November 1, 2013, as amended on June 9, 2014 and November 13, 2014, with a syndicate 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 $2.0 billion, subject to scheduled semi-annual and other elective collateral borrowing base redeterminations based on our oil and natural gas reserves and other factors. The borrowing base is scheduled to be re-determined semi-annually with effective dates of May 1st and November 1st. In addition, we may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2015, the borrowing base was set at $725.0 million, although we elected a commitment amount of $500.0 million. As of September 30, 2015, we had outstanding borrowings of $10.0 million, which bore a weighted-average interest rate of 1.63%, and $490.0 million available for future borrowings under this facility. As of September 30, 2015, the credit agreement was guaranteed by Diamondback, Diamondback E&P LLC and White Fang Energy LLC and will also be guaranteed by any future restricted subsidiaries of Diamondback. The credit agreement is also secured by substantially all of the assets of Diamondback O&G LLC, the Company and the other guarantors.

The outstanding borrowings under the credit agreement bear interest at a rate elected by us 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. We are 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 repaid (a) to the extent that the loan amount exceeds the borrowing base, whether due to a borrowing base redetermination or otherwise (in some cases subject to a cure period), (b) in an amount equal to the net cash proceeds from the sale of property when a borrowing base deficiency or event of default exists under the credit agreement and (c) at the maturity date of November 1, 2018.

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 September 30, 2015, we had $450.0 million of senior unsecured notes outstanding.

As of September 30, 2015, we were in compliance with all financial covenants under our revolving credit facility. The lenders may accelerate all of the indebtedness under our 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. With certain specified exceptions, the terms and provisions of our revolving credit facility generally may be amended with the consent of the lenders holding a majority of the outstanding loans or commitments to lend.

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, which was amended August 15, 2014 to add additional lenders to the lending group, 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 is scheduled to be re-determined semi-annually with effective dates of April 1st and October 1st. The credit agreement was further amended on May 22, 2015 to, among other things, increase the borrowing base from $110.0 million to $175.0 million and to provide for certain restrictions on purchasing margin stock. In addition, the Partnership may request up to three additional redeterminations of the borrowing base during any 12-month period. As of September 30, 2015, the borrowing base remained at $175.0 million and the Partnership had $29.0 million outstanding borrowings.

The outstanding borrowings under the Partnership’s 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 repaid (a) to the extent that 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, purchases of margin stock, 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[(1)]	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

(1) EBITDAX is annualized for the four fiscal quarters ending on the last day of the fiscal quarter for which financial statements are available, beginning with the quarter ended September 30, 2014.

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 credit agreement upon the occurrence and during the continuance of any event of default. The Partnership's 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.

Capital Requirements and Sources of Liquidity

Our board of directors approved a 2015 capital budget for drilling and infrastructure of $400.0 million to $450.0 million (although at the upper end of that range). We estimate that, of these expenditures, approximately:

- $285.0 million to $315.0 million will be spent on drilling and completing 60 to 70 gross (49 to 57 net) operated horizontal wells focused in Midland, Andrews, Upton, Martin and Dawson Counties;
- $20.0 million to $30.0 million will be spent on infrastructure;
- $20.0 million to $30.0 million will be spent on non-operated activity and other expenditures; and
- an estimated $75.0 million for expenditures related to 2014 activity (net of expenditures from 2015 expected to be carried into 2016).

During the nine months ended September 30, 2015, our aggregate capital expenditures for drilling and infrastructure were $326.5 million. We do not have a specific acquisition budget since the timing and size of acquisitions cannot be accurately forecasted. During the nine months ended September 30, 2015, we spent approximately $425.5 million on acquisitions of leasehold interests and $32.3 million on acquisitions of mineral interests. For information regarding our recently completed and pending acquisitions, see "—2015 Highlights—Acquisitions."

The amount and timing of these capital expenditures are largely discretionary and within our control. We could choose to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners.

Based upon current oil and natural gas price and production expectations for 2015, we believe that our cash flow from operations and borrowings under our revolving credit facility will be sufficient to fund our operations through year-end 2015. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. Further, our 2015 capital expenditure budget does not allocate any funds for leasehold interest and property acquisitions.

We monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control. If we require additional capital, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financing, asset sales, offerings of debt and or equity securities or other means. We cannot assure you that the needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our drilling programs, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to replace our reserves.

Contractual Obligations

Except as discussed in Note 14 of the Notes to the Consolidated Financial Statements of this report, there were no material changes to our contractual obligations and other commitments, as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014.

Critical Accounting Policies

There have been no changes in our critical accounting policies from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2014

Off-balance Sheet Arrangements

We had no off-balance sheet arrangements as of September 30, 2015. Please read Note 14 included in Notes to the Combined Consolidated Financial Statements set forth in Part I, Item 1 of this report, for a discussion of our commitments and contingencies, some of which are not recognized in the balance sheets under GAAP.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

Our major market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to our natural gas production. Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control.

We use price swap derivatives to reduce price volatility associated with certain of our oil sales. With respect to these fixed price swap contracts, the counterparty is required to make a payment to us if the settlement price for any settlement period is less than the swap price, and we are required to make a payment to the counterparty if the settlement price for any settlement period is greater than the swap price. Our derivative contracts are based upon reported settlement prices on commodity exchanges, with crude oil derivative settlements based on Argus Louisiana light sweet pricing.

At September 30, 2015, we had a net asset derivative position of $40.0 million, related to our price swap derivatives, as compared to a net asset derivative position of $117.5 million as of December 31, 2014 related to our price swap derivatives. Utilizing actual derivative contractual volumes under our fixed price swaps as of September 30, 2015, a 10% increase in forward curves associated with the underlying commodity would have decreased the net asset position to $35.2 million, a decrease of $4.8 million, while a 10% decrease in forward curves associated with the underlying commodity would have increased the net asset derivative position to $44.8 million, an increase of $4.8 million. However, any cash derivative gain or loss would be substantially offset by a decrease or increase, respectively, in the actual sales value of production covered by the derivative instrument.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from joint interest receivables (approximately $41.0 million at September 30, 2015) and receivables from the sale of our oil and natural gas production (approximately $42.2 million at September 30, 2015).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. For the nine months ended September 30, 2015, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (60%) and Enterprise Crude Oil LLC (14%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (US) Company (64%) and Enterprise Crude Oil LLC

(16%). No other customer accounted for more than 10% of our revenue during these periods.

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells. At September 30, 2015, we had three customers that represented approximately 76% of our total joint operations receivables. At December 31, 2014, we had two customers that represented approximately 61% of our total joint operations receivables.

Interest Rate Risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness under our revolving credit facility. The terms of our revolving credit facility provide for interest on borrowings at a floating rate 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. Our weighted-average interest rate on borrowings under our credit facility was 1.63% at September 30, 2015. An increase or decrease of 1% in the interest rate would have a corresponding decrease or increase in our interest expense of approximately $0.1 million based on the $10.0 million outstanding in the aggregate under our revolving credit facility on September 30, 2015.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Control and Procedures

Under the direction of our Chief Executive Officer and Chief Financial Officer, we have established disclosure controls and procedures, as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act, that are designed to ensure that information required to be disclosed by us in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The disclosure controls and procedures are also intended to ensure that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. In designing and evaluating the disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives. In addition, the design of disclosure controls and procedures must reflect the fact that there are resource constraints and that management is required to apply judgment in evaluating the benefits of possible controls and procedures relative to their costs.

As of September 30, 2015, an evaluation was performed under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Exchange Act. Based upon our evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that as of September 30, 2015, our disclosure controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have not been any changes in our internal control over financial reporting that occurred during the quarter ended September 30, 2015 that have materially affected, or are reasonably likely to materially affect, internal controls over financial reporting.

PART II

ITEM 1. LEGAL PROCEEDINGS

Due to the nature of our business, we are, from time to time, involved in routine litigation or subject to disputes or claims related to our business activities, including workers’ compensation claims and employment related disputes. In the opinion of our management, none of the pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

ITEM 1A. RISK FACTORS

Our business faces many risks. Any of the risks discussed in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also materially impair our business operations, financial condition or future results.

In addition to the information set forth in this report, you should carefully consider the risk factors discussed in Part I, Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2014. There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2014.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Certificate of Incorporation of the Company (incorporated by reference to Exhibit 3.1 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
3.2	Amended and Restated Bylaws of the Company (incorporated by reference to Exhibit 3.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.1	Specimen certificate for shares of common stock, par value $0.01 per share, of the Company (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to the Registration Statement on Form S-1, File No. 333-179502, filed by the Company with the SEC on August 20, 2012).
4.2	Registration Rights Agreement, dated as of October 11, 2012, by and between the Company and DB Energy Holdings LLC (incorporated by reference to Exhibit 4.2 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
4.3	Investor Rights Agreement, dated as of October 11, 2012, by and between the Company and Gulfport Energy Corporation (incorporated by reference to Exhibit 4.3 to the Form 10-Q, File No. 001-35700, filed by the Company with the SEC on November 16, 2012).
10.1*	Lease Amendment No. 11 effective July 31, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.2*	Lease Amendment No. 12 effective October 23, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.3*	Lease Amendment No. 13 effective October 30, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.4*	Lease Amendment No. 14 effective November 10, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.5*	Lease Amendment No. 15 effective November 10, 2014 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.6*	Lease Amendment No. 16 effective April 1, 2015 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
10.7*	Lease Amendment No. 17 effective June 1, 2015 to Lease Agreement dated as of April 19, 2011, as amended, by and between Fasken Midland, LLC and Diamondback E&P LLC.
31.1*	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
31.2*	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(a) promulgated under the Securities Exchange Act of 1934, as amended.
32.1**	Certification of Chief Executive Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
32.2**	Certification of Chief Financial Officer of the Registrant pursuant to Rule 13a-14(b) promulgated under the Securities Exchange Act of 1934, as amended, and Section 1350 of Chapter 63 of Title 18 of the United States Code.
101.INS*	XBRL Instance Document.
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.

*	Filed herewith.
**	The certifications attached as Exhibit 32.1 and Exhibit 32.2 accompany this Annual Report on Form 10-K pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, and shall not be deemed "filed" by the Registrant for purposes of Section 18 of the Securities Exchange Act of 1934, as amended.

SIGNATURES

Pursuant to the requirements of the Securities and 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:	November 5, 2015	/s/ Travis D. Stice Travis D. Stice Chief Executive Officer (Principal Executive Officer)
Date:	November 5, 2015	/s/ Teresa L. Dick Teresa L. Dick Chief Financial Officer (Principal Financial and Accounting Officer)

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