UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2016

OR

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

For the transition period from to

Commission File Number: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3691816** (I.R.S. Employer Identification No.)
321 South Boston, Suite 1000 **Tulsa, Oklahoma** (Address of principal executive offices)	**74103** (Zip Code)

(918) 947-8550

(Registrant s telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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

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

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

The number of shares outstanding of our common stock at November 7, 2016 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	24,699,900

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MIDSTATES PETROLEUM COMPANY, INC.

QUARTERLY REPORT ON

FORM 10-Q

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2016

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GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl: One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe: Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

Boe/day: Barrels of oil equivalent 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.

Dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

Exploratory well: A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

Mcf: One thousand cubic feet of natural gas.

MMBoe: One million barrels of oil equivalent.

MMBtu: One million British thermal units.

Net acres: The percentage of total acres an owner has out of a particular number of acres, or a specified tract.

NYMEX: The New York Mercantile Exchange.

Proved reserves: Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and governmental regulations prior to the time at which contracts providing the right to operate or produce expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

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Reasonable certainty: A high degree of confidence.

Recompletion: The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserves: 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.

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 individual and separate from other reservoirs.

Spud or Spudding: The commencement of drilling operations of a new well.

Wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

Working interest: The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on a cash, penalty, or carried basis.

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PART I - FINANCIAL INFORMATION

MIDSTATES PETROLEUM COMPANY, INC. (DEBTOR-IN-POSSESSION THROUGH OCTOBER 20, 2016)

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share amounts)

	September 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 279,596	$ 81,093
Accounts receivable:		
Oil and gas sales	34,282	33,656
Joint interest billing	5,162	12,503
Other	347	17,506
Other current assets	8,658	1,044
Total current assets	328,045	145,802
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting	3,790,856	3,666,403
Other property and equipment	12,198	14,798
Less accumulated depreciation, depletion, amortization and impairment	(3,438,670)	(3,157,332)
Net property and equipment	364,384	523,869
OTHER NONCURRENT ASSETS	3,263	9,496
TOTAL	**$ 695,692**	**$ 679,167**
LIABILITIES AND STOCKHOLDERS DEFICIT		
CURRENT LIABILITIES:		
Accounts payable	$ 5,653	$ 1,904
Accrued liabilities	71,178	91,712
Debt classified as current (Note 9)	249,383	1,890,944
Total current liabilities	326,214	1,984,560
ASSET RETIREMENT OBLIGATIONS	20,266	18,708
OTHER LONG-TERM LIABILITIES	115	1,965
LIABILITIES SUBJECT TO COMPROMISE (Note 2)	1,882,187	
COMMITMENTS AND CONTINGENCIES (Note 14)		
STOCKHOLDERS DEFICIT:		
Preferred stock, $0.01 par value, 49,675,000 shares authorized; no shares issued or outstanding		
Common stock, $0.01 par value, 100,000,000 shares authorized; 10,914,780 shares issued and 10,766,173 shares outstanding at September 30, 2016 and 10,962,105 shares issued and 10,865,814 shares outstanding at December 31, 2015	109	110
Treasury stock	(3,134)	(3,081)
Additional paid-in-capital	889,973	888,247
Retained deficit	(2,420,038)	(2,211,342)
Total stockholders deficit	(1,533,090)	(1,326,066)

TOTAL	**$**	**695,692**	**$**	**679,167**

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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MIDSTATES PETROLEUM COMPANY, INC. (DEBTOR-IN-POSSESSION THROUGH OCTOBER 20, 2016)

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share amounts)

	For the Three Months Ended September 30, 2016	For the Three Months Ended September 30, 2015	For the Nine Months Ended September 30, 2016	For the Nine Months Ended September 30, 2015
REVENUES:				
Oil sales	$ 35,584	$ 50,684	$ 104,832	$ 177,439
Natural gas liquid sales	8,939	8,498	25,073	29,747
Natural gas sales	17,676	17,375	44,486	52,543
Gains on commodity derivative contracts, net		33,368		35,447
Other	1,994	438	4,322	1,106
Total revenues	64,193	110,363	178,713	296,282
EXPENSES:				
Lease operating and workover	17,650	18,803	49,520	63,823
Gathering and transportation	4,296	4,017	13,428	11,386
Severance and other taxes	1,788	2,660	4,776	8,729
Asset retirement accretion	452	382	1,316	1,217
Depreciation, depletion, and amortization	15,756	44,714	59,229	158,397
Impairment in carrying value of oil and gas properties	33,887	486,895	224,584	1,159,951
General and administrative	3,308	6,677	19,093	29,792
Acquisition and transaction costs		5		256
Debt restructuring costs and advisory fees			7,589	36,141
Other				63
Total expenses	77,137	564,153	379,535	1,469,755
OPERATING LOSS	**(12,944)**	**(453,790)**	**(200,822)**	**(1,173,473)**
OTHER INCOME (EXPENSE):				
Interest income		43	81	80
Interest expense net of amounts capitalized (excludes interest expense of $47.6 and $79.3 million, respectively, on senior and secured notes subject to compromise for the three and nine months ended September 30, 2016)	(2,668)	(40,595)	(65,719)	(121,978)
Reorganization items, net (Note 2)	(22,772)		57,764	
Total other expense	(25,440)	(40,552)	(7,874)	(121,898)
LOSS BEFORE TAXES	**(38,384)**	**(494,342)**	**(208,696)**	**(1,295,371)**
Income tax benefit				9,041
NET LOSS	**$ (38,384)**	**$ (494,342)**	**$ (208,696)**	**$ (1,286,330)**

Preferred stock dividend				(148)				(948)
NET LOSS ATTRIBUTABLE TO COMMON SHAREHOLDERS	**$**	**(38,384)**	**$**	**(494,490)**	**$**	**(208,696)**	**$**	**(1,287,278)**
Basic and diluted net loss per share attributable to common shareholders	$	(3.60)	$	(72.34)	$	(19.61)	$	(189.90)
Basic and diluted weighted average number of common shares outstanding		10,657		6,835		10,644		6,779

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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MIDSTATES PETROLEUM COMPANY, INC. (DEBTOR-IN-POSSESSION THROUGH OCTOBER 20, 2016)

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS EQUITY (DEFICIT)

(Unaudited)

(In thousands)

	Series A Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in-Capital	Retained Deficit	Total Stockholders Deficit
Balance as of December 31, 2015	**$**	**$ 110**	**$ (3,081)**	**$ 888,247**	**$ (2,211,342)**	**$ (1,326,066)**
Share-based compensation		(1)		1,726		1,725
Acquisition of treasury stock			(53)			(53)
Net loss					(208,696)	(208,696)
Balance as of September 30, 2016	**$**	**$ 109**	**$ (3,134)**	**$ 889,973**	**$ (2,420,038)**	**$ (1,533,090)**

	Series A Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in-Capital	Retained Deficit	Total Stockholders Equity (Deficit)
Balance as of December 31, 2014	**$ 3**	**$ 70**	**$ (2,592)**	**$ 882,528**	**$ (414,147)**	**$ 465,862**
Share-based compensation		3		4,930		4,933
Acquisition of treasury stock			(476)			(476)
Net loss					(1,286,330)	(1,286,330)
Conversion of preferred shares	(3)	37		(34)		
Balance as of September 30, 2015	**$**	**$ 110**	**$ (3,068)**	**$ 887,424**	**$ (1,700,477)**	**$ (816,011)**

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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MIDSTATES PETROLEUM COMPANY, INC. (DEBTOR-IN-POSSESSION THROUGH OCTOBER 20, 2016)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	For the Nine Months Ended September 30, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (208,696)	$ (1,286,330)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Gains on commodity derivative contracts, net		(35,447)
Net cash received for commodity derivative contracts		129,105
Asset retirement accretion	1,316	1,217
Depreciation, depletion, and amortization	59,229	158,397
Impairment in carrying value of oil and gas properties	224,584	1,159,951
Share-based compensation, net of amounts capitalized to oil and gas properties	1,275	3,813
Deferred income taxes		(9,041)
Amortization of deferred financing costs and write-off of debt issuance costs	4,495	9,791
Paid-in-kind interest expense	3,531	3,785
Amortization of deferred gain on debt restructuring	(8,246)	(8,979)
Operating lease abandonment	1,574	
Noncash reorganization items	(70,489)	
Transaction costs for debt restructuring		34,398
Change in operating assets and liabilities:		
Accounts receivable oil and gas sales	(311)	18,183
Accounts receivable JIB and other	21,411	28,293
Other current and noncurrent assets	(5,572)	(287)
Accounts payable	870	(3,448)
Accrued liabilities	54,520	33,036
Other	(1,247)	(545)
Net cash provided by operating activities	**$ 78,244**	**$ 235,892**
CASH FLOWS FROM INVESTING ACTIVITIES:		
Investment in property and equipment	(129,072)	(271,576)
Proceeds from the sale of oil and gas properties		40,168
Net cash used in investing activities	**$ (129,072)**	**$ (231,408)**
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long-term borrowings		625,000
Proceeds from revolving credit facility	249,384	33,000
Repayment of revolving credit facility		(468,150)
Deferred financing costs		(4,234)
Transaction costs for debt restructuring		(34,398)
Acquisition of treasury stock	(53)	(476)
Net cash provided by financing activities	**$ 249,331**	**$ 150,742**
NET INCREASE IN CASH AND CASH EQUIVALENTS	**$ 198,503**	**$ 155,226**
Cash and cash equivalents, beginning of period	**$ 81,093**	**$ 11,557**

Cash and cash equivalents, end of period	**$**	**279,596**	**$**	**166,783**
SUPPLEMENTAL INFORMATION:				
Non-cash investment in property and equipment	$	12,238	$	36,373
Non-cash exchange of third lien notes for 2020 senior notes and 2021 senior notes				524,121
Cash paid for interest, net of capitalized interest of $2.9 million for the nine months ended September 30, 2015 (no capitalized interest for the nine months ended September 30, 2016)		5,821		70,711
Cash paid for reorganization items		12,725		

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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MIDSTATES PETROLEUM COMPANY, INC. (DEBTOR-IN-POSSESSION THROUGH OCTOBER 20, 2016)

Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Business

Midstates Petroleum Company, Inc. (Midstates), through its wholly owned subsidiary Midstates Petroleum Company LLC (Midstates Sub), engages in the business of exploring, drilling for, and the production of, oil, natural gas liquids (NGLs) and natural gas. Midstates was incorporated pursuant to the laws of the State of Delaware on October 25, 2011 in connection with its initial public offering to become a holding company for Midstates Sub, which was previously a wholly owned subsidiary of Midstates Petroleum Holdings LLC (Holdings LLC). The terms Company, we, us, our, and similar terms when used in the present tense, prospectively or for historical periods since April 25, 2012, refe to Midstates and Midstates Sub, unless the context indicates otherwise.

The Company conducts oil and gas operations and owns and operates oil and natural gas properties in Oklahoma, Texas and Louisiana. The Company operates a significant portion of its oil and natural gas properties. The Company s management evaluates performance based on one reportable segment as all of its operations are located in the United States and, therefore, it maintains one cost center.

2. Chapter 11 Proceedings

Voluntary Reorganization Under Chapter 11

On April 30, 2016 (the Petition Date), Midstates and Midstates Sub (collectively, the Debtors), filed voluntary petitions (the Bankruptcy Petitions) for reorganization under Title 11 of Chapter 11 of the United States Code (the Bankruptcy Code) in the United States Bankruptcy Court for the Southern District of Texas (the Bankruptcy Court). The Debtors Chapter 11 cases (the Chapter 11 Cases) were jointly administered under the case styled *In re Midstates Petroleum Company, Inc., et al, No. 16-32237.* The Bankruptcy Court confirmed the *First Amended Joint Chapter 11 Plan of Reorganization of Midstates Petroleum Company, Inc., and its Debtor Affiliate* (the Plan) on September 28, 2016 and the Debtors subsequently emerged from bankruptcy on October 21, 2016 (the Effective Date). Although the Company is no longer a debtor-in-possession, the Company was a debtor-in-possession for the quarter ended September 30, 2016 and through October 20, 2016, the date immediately prior to the Effective Date. As such, certain aspects of the Chapter 11 Cases and related matters are described below in order to provide context to the Company s financial condition and results of operations for the period presented.

For the quarter ended September 30, 2016, the Debtors operated their businesses as debtors-in-possession under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of the Bankruptcy Code and orders of the Bankruptcy Court. During the Chapter 11 Cases, the Company conducted normal business activities pursuant to certain first day motions filed in the Chapter 11 Cases and approved by the Bankruptcy Court to, among other things and subject to the terms of the orders entered by the Bankruptcy Court, pay employee wages, health benefits and certain other employee obligations, pay certain lienholders or prospective lienholders and forward funds to third parties, including royalty holders and other working interest owners. As a result of these motions, the Company was able to pay all associated obligations for the period following the Petition Date. Additionally, the Company was authorized to pay and has paid pre-petition tax obligations, pre-petition employee wages and benefits, pre-petition amounts owed to certain lienholders or prospective lienholders and funds belonging to third parties. During the pendency of the Chapter 11 Cases, all transactions outside the ordinary course of business require the prior approval of the Bankruptcy Court. The Company has accounted for the bankruptcy in accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification (ASC) 852, *Reorganizations*.

The Debtors Plan was supported by the vast majority of its pre-petition secured creditors and was confirmed by the Bankruptcy Court on September 28, 2016. Pursuant to the confirmed Plan, the significant transactions that occurred upon the Effective Date were as follows:

- Substantial Deleveraging of the Balance Sheet: The permanent pay-down of $81.3 million of the Company s Credit Facility, with a $170.0 million exit facility (the Exit Facility) established upon the Effective Date, (ii) the pay-down of $60.0 million of the Company s Second Lien Notes in cash, and (iii) the conversion into equity of all of the Company s remaining debt junior to the Credit Facility.

- Credit Facility Claims: Holders of allowed claims arising under the Credit Facility (the Credit Facility Claims) received their pro rata share of approximately $81.3 million in cash and the Credit Facility was superseded, pursuant to the Plan, by the Exit Facility, as further described below.

- Second Lien Notes Claims: Holders of allowed claims arising under the Second Lien Notes (the Second Lien Notes Claims) received their pro rata share of (a) 96.25% of the equity of the reorganized Company in the form of common stock and (b) a cash payment of $60.0 million.

- Third Lien Notes Claims: Holders of allowed claims arising under the Third Lien Notes (the Third Lien Notes Claims), pursuant to a settlement with holders of Second Lien Notes Claims on terms more fully set forth in the Plan (the Second/Third Lien Plan Settlement), received their pro rata share of 2.5% of the equity in the form of common stock in the reorganized Company and warrants to acquire 4,411,765 shares of common stock in the reorganized Company with a strike price of $24.00 per common share and expiring 42 months after the Effective Date.

- Unsecured Claims: Holders (the Unsecured Noteholders) of allowed claims arising under the Debtors 10.75% Senior Unsecured Notes due 2020 (the 2020 Notes Claims), the holders of allowed claims arising under the 9.25% Senior Unsecured Notes due 2021 (the 2021 Notes Claims, and together with the 2020 Notes Claims, the Unsecured Notes Claims), and the Holders of other general unsecured claims received their pro rata share of 1.25% of the equity in the form of common stock in the reorganized Company and warrants to acquire 2,213,789 shares of common stock in the reorganized Company (the Unencumbered Assets Equity Distribution) with a strike price of $46.00 per common share and expiring 42 months after the Effective Date.

- Existing Equity: All existing equity interests of the Company were extinguished, and existing equity holders did not receive any consideration in respect of their equity interests.

- New Equity: On the Effective Date, the Company issued 24,687,500 shares of common stock in the reorganized Company and will issue 312,500 additional common shares pursuant to the Plan in a future distribution. The total authorized capital stock of the reorganized Company consists of 250,000,000 shares of common stock and 50,000,000 shares of preferred stock.

- Exit Facility: The Company s Credit Facility, which was redetermined with a borrowing base of $170.0 million in April 2016, was superseded, pursuant to the Plan, by the Exit Facility. The Exit Facility has an initial borrowing base of $170.0 million with no borrowing base redeterminations to occur until April 2018 (provided certain conditions are met) and semiannual borrowing base redeterminations each year on April 1 and October 1 thereafter. The Exit Facility matures on September 30, 2020 with interest payable at LIBOR plus 4.50% per annum, subject to a 1.00% LIBOR floor. The Exit Facility is secured by first priority mortgages on at least 95.0% of the proved oil and gas reserves and all other oil and gas properties included in the most recently delivered reserve report, pledges of capital stock, a first priority security interest in the cash, cash equivalents, deposit, securities and other similar accounts, and a first-priority perfected security interest in substantially all other tangible and intangible assets (including but not limited to as-extracted collateral, accounts receivable, inventory, equipment, general intangibles, investment property, intellectual property, real property and the proceeds of the foregoing). Until April 2018, unless the borrowing base is redetermined earlier, the amount available to be drawn under the Exit Facility is reduced by $40.0 million, and thereafter, the Company must maintain liquidity equal to at least 20.0% of the effective borrowing base. In connection therewith, on the the Effective Date, the Company made an additional payment of $40.0 million to lenders under its Exit Facility. In addition to the aforementioned liquidity covenant, the Exit Facility also contains various other financial covenants, including an EBITDA to interest expense coverage ratio limitation of 3.00:1.00, a ratio limitation of Total Net Indebtedness (as defined in the Exit Facility) to EBITDA of not more than 2.25:1.00 through April 1, 2018 and not more than 3.00:1.00 thereafter, and a capital expenditure limitation of $50.0 million for the 6 months ended December 31, 2016, $81.0 million for the year ended December 31, 2017, $85.0 million for the year ended December 31, 2018 and $78.0 million for the year ended December 31, 2019. The Exit Facility is also subject to a variety of other terms and conditions including conditions precedent to funding and various other covenants and representations and warranties.

- Management Incentive Plan: A management equity incentive plan (the MIP) was established under which 10% of the equity in the reorganized Company (on a fully-diluted/fully-distributed basis) was reserved for grants to be made from time to time to the directors, officers, and other members of management of the reorganized Company.

In accordance with the Plan, the reorganized Company s new board of directors is made up of seven directors consisting of the President and Chief Executive Officer of the reorganized Company (Frederic F. Brace), one member of the Company s pre-bankruptcy board of directors (Alan J. Carr, who will also serve as non-executive chairman of the Board), and five newly-appointed members selected by the holders of the Second Lien Notes Claims (Patrice Douglas, Neal P. Goldman, Todd R. Snyder, Michael S. Reddin, and Bruce H. Vincent).

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Fresh Start Accounting

Upon emergence from the Chapter 11 Cases on the Effective Date, the Company will be required to apply fresh start accounting to its consolidated financial statements because (i) the holders of voting shares of the Company prior to the Effective Date received less than 50% of the voting shares of the Company following its emergence from the Chapter 11 Cases and (ii) the reorganization value of its assets immediately prior to confirmation of the Plan was less than the post-petition liabilities and allowed claims. Under the principles of fresh start accounting, a new reporting entity was considered to be created upon emergence. The Company will allocate the reorganization value of the Company to its individual assets based on their estimated fair values as of that date. As a result of the application of fresh start accounting and the effects of the implementation of the Plan, the Company s consolidated financial statements on and after the Effective Date will not be comparable with the Company s consolidated financial statements prior to that date.

Financial Statement Classification of Liabilities Subject to Compromise

Liabilities subject to compromise represent liabilities incurred prior to the Petition Date which are affected by the Chapter 11 Cases. These amounts represent the Company s allowed claims and its best estimate of claims expected to be allowed which will be resolved as part of the Chapter 11 Cases. Such claims remain subject to future adjustments and resolution of certain of these claims has and will extend beyond the Effective Date. Adjustments may result from negotiations, actions of the Bankruptcy Court, determination as to the value of any collateral securing claims or various other events. A difference between liability amounts estimated by the Company and claims filed by creditors will be investigated and the Bankruptcy Court will make a final determination of the amount of allowable claims. As of September 30, 2016 liabilities subject to compromise consist of the following:

		As of September 30, 2016 (in thousands)
Debt:		
2020 Senior Notes (including accrued interest as of the Petition Date)	$	312,039
2021 Senior Notes (including accrued interest as of the Petition Date)		361,050
Second Lien Notes (including accrued interest as of the Petition Date)		651,042
Third Lien Notes (including accrued interest as of the Petition Date)		556,136
Total debt (including accrued interest as of the Petition Date)		1,880,267
Accounts payable and accrued liabilities		1,920
Total liabilities subject to compromise	**$**	**1,882,187**

Interest Expense

The Debtors discontinued recording interest on liabilities subject to compromise upon the Petition Date. Contractual interest on liabilities subject to compromise not reflected in the condensed consolidated statements of operations for the three and nine months ended September 30, 2016 was approximately $47.6 million and $79.3 million, respectively, representing interest expense incurred subsequent to the Petition Date.

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Reorganization Items

Reorganization items represent the direct and incremental costs of being in bankruptcy, such as professional fees, pre-petition liability claim adjustments and losses related to terminated contracts that are probable and can be estimated. Unamortized deferred financing costs as well as unamortized gains on the May 2015 troubled debt restructuring associated with debt classified as liabilities subject to compromise were also reclassified to reorganization items in order to reflect the expected amounts of allowed claims. Reorganization items consisted of the following for the three and nine months ended September 30, 2016:

	For the Three Months Ended September 30, 2016	For the Nine Months Ended September 30, 2016
	(in thousands)	
Professional fees incurred (1)	$ (24,131)	$ (31,593)
Adjustment to unamortized debt issuance costs associated with 2020 Senior Notes		(10,738)
Adjustment to unamortized debt issuance costs associated with 2021 Senior Notes		(12,671)
Adjustment to unamortized gain on troubled debt restructuring associated with Second Lien Notes		39,599
Adjustment to unamortized gain on troubled debt restructuring associated with Third Lien Notes		71,808
Other (2)	1,359	1,359
Total reorganization items, net	**$ (22,772)**	**$ 57,764**

(1) Through September 30, 2016, the Company has incurred significant professional fees associated with various advisors engaged in the restructuring process. In addition, the Company paid certain advisors success fees upon its emergence from bankruptcy on October 21, 2016. Success fees of $7.3 million were earned on September 28, 2016, the Company s bankruptcy confirmation date, and as such were accrued and included in the above table under the heading professional fees incurred.

(2) Other reorganization items recorded in the third quarter of 2016 include $0.2 million related to Houston office fixed assets, which were abandoned, as well as a $1.6 million decrease in the liability previously recorded for the abandonment of the Houston office lease.

3. Summary of Significant Accounting Policies

Basis of Presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (GAAP) for complete consolidated financial statements, and should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2015 included in the Company s Annual Report on Form 10-K as filed with the

SEC on March 30, 2016.

The condensed consolidated financial statements for the quarter ended September 30, 2016 have been prepared in accordance with FASB ASC Topic 852, *Reorganizations*. This guidance requires that transactions and events directly associated with the Chapter 11 reorganization be distinguished from the ongoing operations of the business. In addition, the guidance provides for changes in the accounting for and presentation of liabilities. See Note 2. Chapter 11 Proceedings.

All intercompany transactions have been eliminated in consolidation. In the opinion of the Company s management, the accompanying unaudited condensed consolidated financial statements include all adjustments, consisting of normal recurring adjustments, necessary to fairly present the financial position as of, and the results of operations for, all periods presented. In preparing the accompanying condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

On the Effective Date, the Company emerged from the Chapter 11 Cases after completing all required actions and satisfying the remaining conditions to its Plan, which was confirmed by the Bankruptcy Court by an order entered on September 28, 2016. The Company cannot currently estimate the financial effect of its emergence from bankruptcy on its financial statements, although it expects to record material adjustments due to the Plan and the application of fresh start accounting guidance at the Effective Date.

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Recently Issued Standards Not Yet Adopted

In May 2014, the FASB issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)* (ASU 2014-09). ASU 2014-09 provides guidance concerning the recognition and measurement of revenue from contracts with customers. The objective of ASU 2014-09 is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. ASU 2014-09 requires an entity to (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. ASU 2014-09 will be effective for the Company beginning on January 1, 2018, including interim periods within that reporting period, after considering the one year deferral provided by ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.* The standard permits the use of either the retrospective or cumulative effect transition method and early adoption is permitted. The Company has not selected a transition method and is evaluating the impact this standard will have on its condensed consolidated financial statements and related disclosures.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)* (ASU 2016-02). ASU 2016-02 establishes a right-of-use (ROU) model that requires a lessee to record a ROU asset and a lease liability on the balance sheet for all leases with terms longer than 12 months. Leases will be classified as either finance or operating, with classification affecting the pattern of expense recognition in the income statement. The new standard is effective for the Company beginning on January 1, 2019, including interim periods within that fiscal year. A modified retrospective transition approach is required for lessees for capital and operating leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company is currently evaluating the impact this standard will have on its condensed consolidated financial statements and related disclosures.

In March 2016, the FASB issued ASU 2016-09, *Compensation Stock Compensation (Topic 718)* (ASU 2016-09). ASU 2016-09 simplifies how certain aspects of share-based payments to employees are recorded. ASU 2016-09 requires that entities recognize the income tax effects of awards in the income statement when the awards vest or are settled, provides guidance on the classification of certain aspects of share-based payments on the statement of cash flows, changes the threshold for awards to qualify for equity classification, and allows an entity to make an accounting policy election to account for forfeitures when they occur. The new standard is effective for the Company beginning on January 1, 2017. The Company is currently evaluating the impact this standard will have on its condensed consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows Classification of Certain Cash Receipts and Cash Payments* (ASU 2016-15). ASU 2016-15 addresses eight specific cash flow issues with the objective of reducing existing diversity of practice. The eight specific cash flow issues contained within ASU 2016-15 are debt prepayment or debt extinguishment costs, settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. ASU 2016-15 is effective for the Company for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years. The Company does not believe the adoption of ASU 2016-15 will have a material impact on its cash flows.

4. Risk Management and Derivative Instruments

Revenue realized by the Company from the sale of its production is exposed to fluctuations in the prices for crude oil, NGLs and natural gas. The Company has historically utilized various types of derivative financial instruments, including swaps and collars, to reduce fluctuations in cash flows resulting from changes in commodity prices. Although the Company has entered into derivative financial instruments in the past, the Company currently has no derivatives in place.

Commodity Derivative Contracts

As of September 30, 2016 and December 31, 2015, the Company did not have any open commodity derivative contract positions.

Gains on Commodity Derivative Contracts

Historically, the Company has not designated its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, commodity derivative contracts are marked-to-market each quarter with the change in fair value during the periodic reporting period recognized in Gains on commodity derivative contracts - net within revenues in the unaudited condensed consolidated statements of operations.

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The following table presents net cash received for commodity derivative contracts and unrealized net losses recorded by the Company related to the change in the fair value of the derivative instruments in Gains on commodity derivative contracts, net for the periods presented:

	For the Three Months Ended September 30, 2016		For the Three Months Ended September 30, 2015		For the Nine Months Ended September 30, 2016		For the Nine Months Ended September 30, 2015	
	(in thousands)							
Net cash received for commodity derivative contracts	$		$	34,307	$		$	129,105
Unrealized net losses				(939)				(93,658)
Gains on commodity derivative contracts - net	**$**		**$**	**33,368**	**$**		**$**	**35,447**

5. Property and Equipment

Property and equipment consisted of the following as of the dates presented:

	September 30, 2016		December 31, 2015	
	(in thousands)			
Oil and gas properties, on the basis of full-cost accounting:				
Proved properties	$	3,790,856	$	3,666,403
Unevaluated properties				
Other property and equipment		12,198		14,798
Less accumulated depreciation, depletion, amortization and impairment		(3,438,670)		(3,157,332)
Net property and equipment	**$**	**364,384**	**$**	**523,869**

Oil and Gas Properties

The Company capitalizes internal costs directly related to exploration and development activities to oil and gas properties. During the three and nine months ended September 30, 2016 and 2015, the Company capitalized the following (in thousands):

	Three Months Ended September 30, 2016		Three Months Ended September 30, 2015		Nine Months Ended September 30, 2016		Nine Months Ended September 30, 2015	
	(in thousands)							
Internal costs capitalized to oil and gas properties(1)	$	1,049	$	1,632	$	3,311	$	6,547

(1) Inclusive of $0.1 million and $0.3 million of qualifying share-based compensation expense for the three months ended September 30, 2016 and 2015, respectively. For the nine months ended September 30, 2016 and 2015, inclusive of $0.5 million and $1.1 million, respectively.

The Company accounts for its oil and gas properties under the full cost method. Under the full cost method, proceeds realized from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion of the Company s reserve quantities are sold such that it results in a significant alteration of the relationship between capitalized costs and remaining proved reserves, in which case a gain or loss is generally recognized in income.

The Company performs a full-cost ceiling test on a quarterly basis. The test establishes a limit (ceiling) on the book value of the Company s oil and gas properties. The capitalized costs of oil and gas properties, net of accumulated depreciation, depletion, amortization and impairment (DD&A) and the related deferred income taxes, may not exceed this ceiling. The ceiling limitation is equal to the sum of: (i) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations accrued on the balance sheet, calculated using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved and unevaluated properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged to expense in the accompanying consolidated statements of operations.

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For the three and nine months ended September 30, 2016, capitalized costs exceeded the ceiling and the Company recorded an impairment of oil and gas properties of $33.9 million and $224.6 million, respectively. The comparable three and nine month periods ended September 30, 2015 included impairments of oil and gas properties of $486.9 million and $1.2 billion, respectively. These impairments were primarily the result of continued low commodity prices, which resulted in a reduction of the discounted present value of the Company s proved oil and natural gas reserves.

Depreciation, depletion and amortization is calculated using the Units of Production Method (UOP). The UOP calculation multiplies the percentage of estimated proved reserves produced by the cost of those reserves. The result is to recognize expense at the same pace that the reservoirs are estimated to be depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated depreciation, depletion, amortization and impairment, estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value. The following table presents depletion expense related to oil and gas properties for the three and nine months ended September 30, 2016 and 2015, respectively:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2016	2015	2016	2015	2016	2015	2016	2015
	(in thousands)		(per Boe)		(in thousands)		(per Boe)	
Depletion expense	$ 15,231	$ 43,814	$ 5.90	$ 14.60	$ 57,018	$ 155,778	$ 6.92	$ 17.01
Depreciation on other property	525	900	0.20	0.30	2,211	2,619	0.27	0.29
Depreciation, depletion, and amortization	**$ 15,756**	**$ 44,714**	**$ 6.10**	**$ 14.90**	**$ 59,229**	**$ 158,397**	**$ 7.19**	**$ 17.30**

Other Property and Equipment

Other property and equipment consists of vehicles, furniture and fixtures, and computer hardware and software and are carried at cost. Depreciation is calculated principally using the straight-line method over the estimated useful lives of the assets, which range from five to seven years. Maintenance and repairs are charged to expense as incurred, while renewals and betterments are capitalized.

6. Other Noncurrent Assets

The following table presents the components of other noncurrent assets as of the dates presented:

$
409.0

$

404.9

Our senior notes due in 2017, 2020 and 2022 are stated as liabilities at carrying value on our accompanying condensed consolidated balance sheets, net of any discount or premium. If we recorded these notes at fair value they would be Level 1 in our fair value hierarchy as they are traded in an active market with quoted prices for identical instruments.

The following table presents our assets and liabilities that are measured at fair value as of March 31, 2014 and December 31, 2013, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 2 of these condensed consolidated financial statements. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total Assets / Liabilities	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
March 31, 2014				
Assets:				
Natural Gas Derivatives	$0.3	$—	$0.3	$—
Liabilities:				
Natural Gas Derivatives	2.7	—	2.7	—
Gas Basis Derivatives	0.3	—	0.3	—
Oil Derivatives	0.8	—	0.8	—
December 31, 2013				
Assets:				
Natural Gas Derivatives	$0.5	$—	$0.5	$—
Oil Derivatives	0.3	—	0.3	—
Liabilities:				
Natural Gas Derivatives	0.7	—	0.7	—
Oil Derivatives	0.2	—	0.2	—

Our unsettled derivative assets and liabilities in the table above are measured at gross fair value and are shown on the accompanying condensed consolidated balance sheets in “Other current assets” and "Accounts payable and accrued liabilities", respectively.

Level 1 – Uses quoted prices in active markets for identical, unrestricted assets or liabilities. Instruments in this category have comparable fair values for identical instruments in active markets.

Level 2 – Uses quoted prices for similar assets or liabilities in active markets or observable inputs for assets or liabilities in non-active markets. Instruments in this category are periodically verified against quotes from brokers and include our commodity derivatives that we value using commonly accepted industry-standard models which contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data that are obtained from independent third-party sources.

Level 3 – Uses unobservable inputs for assets or liabilities that are in non-active markets. We do not have any assets or liabilities in this category that are not supported by market activity and have significant unobservable inputs.

(8) Condensed Consolidating Financial Information

Swift Energy Company (the parent) is the issuer and Swift Energy Operating, LLC (a wholly owned indirect subsidiary of Swift Energy Company) is the sole guarantor of our senior notes due in 2017, 2020 and 2022. Swift Energy Company does not have any independent assets or operations. The guarantees on our senior notes due in 2017, 2020 and 2022 are full and unconditional. All subsidiaries of Swift Energy Company, other than Swift Energy Operating, LLC, are minor.

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual reports on Form 10-K for the years ended December 31, 2013 and 2012. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 25 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development and are one of the largest producers of crude oil in the state of Louisiana. Oil production accounted for 32% of our first quarter 2014 production and 62% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 48% of our first quarter 2014 production and 74% of our oil and gas sales. In recent periods, this has allowed us to benefit from better margins for oil production, as oil prices are significantly higher on a Boe basis than natural gas prices.

First Quarter 2014 Activities

- Production: Our production volumes increased by 4% in the first quarter of 2014 when compared to volumes in the same period in 2013 as oil volumes decreased by 6%, NGL volumes decreased by 14% and natural gas production volumes increased by 21%. The change in oil production volumes resulted from our Southeast Louisiana operations while the change in NGL and natural gas volumes primarily came from our South Texas operations. Sequentially, production volumes decreased by 5% in the first quarter of 2014 compared to fourth quarter of 2013 levels as oil volumes decreased by 9%, NGL volumes decreased by 22% and natural gas production volumes increased by 6%. The change in oil production volumes are attributable to operations in our South Texas and Southeast Louisiana areas while the change in NGL and natural gas volumes was primarily from our South Texas area.

- Pricing: Our weighted average sales price in the first quarter of 2014 decreased by 3% when compared to average price levels in the first quarter of 2013. When compared to pricing in the first quarter of 2013, oil prices in the first quarter of 2014 decreased 8%, NGL prices increased 21% and natural gas prices increased 42%. Sequentially, when comparing first quarter of 2014 pricing to pricing in the fourth quarter of 2013, oil prices increased 6%, NGL prices increased 7% and natural gas prices increased 26%.

- Cash provided by operating activities: For the first three months of 2014, our cash provided by operating activities increased by $7.5 million or 12%, when compared to levels in the first three months of 2013, due primarily to working capital changes.

- Available liquidity: At March 31, 2014, we had $297.7 million in outstanding borrowings under our credit facility. Our borrowing base and commitment amount under the credit facility is $450.0 million, which provides us with approximately $152 million of liquidity. We plan to utilize amounts received from any asset sales and joint ventures entered into during 2014 to strengthen our balance sheet and fund a portion of our 2014 capital expenditures. The completion of either of these transactions will affect our 2014 capital expenditures as we align our capital expenditures with our expected cash flows.

- 2014 capital expenditures: Our capital expenditures on a cash flow basis were $105.6 million in the first three months of 2014, compared to $133.0 million in the first three months of 2013. The expenditures were mainly due to drilling and completion activity in our South Texas core region as we drilled six wells in our AWP Eagle Ford field and five wells in our Fasken field. These expenditures were funded by $69.7 million of cash provided by operating activities and the remainder through borrowings under our credit facility.

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Strategy and Outlook

- Full Year 2014 Planned Capital Expenditures: Our 2014 planned capital expenditures are $300 to $350 million. We currently plan to fund our 2014 capital expenditures with our operating cash flow. We expect that a portion of any proceeds from joint ventures we enter involving our properties in the Fasken Eagle Ford area (see below) and/or proceeds from the disposition of all or a portion of our Central Louisiana assets (see below) will allow us to increase our level of capital expenditures while still allowing us to reduce our debt. If we do not receive such joint venture or disposition proceeds, we will align our capital spending with our expected cash flows. These amounts are flexible and will be adjusted based on the timing of any joint venture or disposition transactions and market fundamentals. For 2014, the Company continues to target annual production levels of 11.3 to 11.8 MMBoe based on the above spending levels.

- Pursuit of Eagle Ford Joint Venture: We are currently engaged in negotiations regarding a joint venture arrangement for a portion of our natural gas properties in the Eagle Ford area, principally our natural gas properties in the Fasken area. Entering into a joint venture agreement could accelerate drilling and development, monetize a portion of those asset values and further diversify our risk profile. We are targeting completion of this initiative by mid-year 2014.

- Central Louisiana Property Disposition: We are currently negotiating with prospective buyers to sell some or all of our Austin Chalk and Wilcox assets in Central Louisiana in order to focus our spending on our South Texas properties. We will continue these negotiations and expect to either complete a sale of some or all of these properties or pursue an ongoing development plan of our own. These Central Louisiana assets include approximately 86,000 mineral acres and three producing oil and natural gas fields: Burr Ferry, Masters Creek, and South Bearhead Creek.

- Reduced Spending for 2014: We are planning a reduced level of capital spending for 2014 to levels more in line with our internally generated cash flow and some portion of any joint venture and/or disposition. Our priorities are financial discipline first and growth second. We expect to continue focusing on South Texas production and reserves, while maintaining a stronger balance sheet. Either or both transactions discussed above would initially reduce the borrowing base on our line of credit, but would also lower our leverage and enhance our liquidity, given that the expected proceeds would exceed any associated borrowing base reduction. We have been and will continue taking steps to reduce our future operating and overhead costs through a number of initiatives, including reducing personnel in conjunction with any asset dispositions and alignment of our other expenses, including the cancellation of a new lease for future corporate office space, which will allow us to seek out more efficient and cost effective space.

- Operating improvements through new Eagle Ford drilling and completion technology: Our South Texas drilling activities continue to benefit from optimized well design as we are drilling longer laterals in our horizontal wells and performing more frac stages per well. When we began drilling in the Eagle Ford, our average lateral length was approximately 3,000 feet, and we performed up to nine frac stages per well. Our current process allows us to drill laterals of over 6,000 feet and complete 20 or more frac stages per well. We have observed a high correlation between the lateral length and number of frac stages in horizontal Eagle Ford wells, along with improved initial performance and long-term cumulative production. Additionally, as several of our peers have also announced, we are now increasing the number of frac stages per 1,000 feet of lateral length and using greater amounts of proppant with each frac as we believe these changes could bring further improvement in our results.

- Improved performance of Eagle Ford shale assets through reduction in per well costs: We have seen improved performance this year in our initial production (IP) rates for Eagle Ford wells and have also seen our per well drilling and completion costs come down from those experienced in the prior year. With faster drilling times, we are currently able to drill more wells per rig than previously expected. We have also experienced efficiency gains in our hydraulic fracturing activities (fracs), which enable us to perform more frac stages per month, lower the overall frac cost per stage and achieve better overall results. We believe that progression along this technology learning curve is important to improving performance and reducing costs. As an example, we continued to see excellent production results from our recently completed wells in our Fasken area during the first quarter of 2014, which have been our most prolific wells in that area.

- Advances in 3D Geoscience technologies allow more targeted drilling: We are utilizing state of the art geoscience technologies to improve our lateral placements and completion design in the Eagle Ford and to better define our undeveloped resource potential in Lake Washington. In the Eagle Ford, GEOFRAC logging of the horizontal well bore has led to more effective placement of frac stages and also assisted in identifying sections of rock that are not ideal for stimulation, affording opportunities to eliminate potentially non-productive frac stages. We have been able to utilize our 3D seismic data in this area, along with the analysis of cores and well logs, to identify a narrow high quality interval of

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the lower Eagle Ford within which to steer our laterals, resulting in marked improvement in our well results. We recently acquired 3D seismic data over our Fasken area, which we believe will allow us additional improvement in drilling results in this area. In our Lake Washington area, we have applied new state of the art tools to better define the undeveloped resources in the field. We recently obtained some additional 3D seismic data over the southern area at Lake Washington and will be merging and reprocessing it with our proprietary 3D seismic data. With the help of this new data along with these new tools, we expect to identify additional unevaluated development potential in this field.

- Ability to capitalize on increased natural gas prices in the future: Although current natural gas prices are lower than historical highs, prices have improved significantly from the lows seen in the last several years. With increasing demand, including the volume of LNG available for export increasing over the next several years, we believe natural gas prices will increase from current levels and that selected natural gas properties can be economically developed in today's market, although much of the potential for natural gas development will require higher prices. Our Fasken properties in Webb County, which include some of the best Eagle Ford rock in South Texas as defined by porosity, total organic content and other geologic and petrophysical qualities, can be economically developed today. Some areas such as potential natural gas resources in our South AWP area in McMullen County may require a higher price environment to provide adequate economic returns, but we believe there are other potential areas in South Texas that can be developed economically in the current environment. Our strategy includes a balanced approach to oil and natural gas, and as such, we plan to continue some development on our prolific natural gas properties, such as Fasken.

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Results of Operations

Revenues — Three Months Ended March 31, 2014 and 2013

Our oil and gas sales in the first quarter of 2014 increased by 1% compared to oil and gas sales in the first quarter of 2013, due to higher natural gas pricing and production, partially offset by lower oil pricing and production. Average oil prices we received were 8% lower than those received during the first quarter of 2013, while natural gas prices were 42% higher, and NGL prices were 21% higher.

Crude oil production was 32% and 35% of our production volumes in the three months ended March 31, 2014 and 2013, respectively. Crude oil sales were 62% and 73% of oil and gas sales in the three months ended March 31, 2014 and 2013, respectively. Natural gas production was 52% and 45% of our production volumes in the three months ended March 31, 2014 and 2013, respectively. Natural gas sales were 26% and 15% of oil and gas sales in the three months ended March 31, 2014 and 2013, respectively. The remaining production and sales in each period was from NGLs.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the three months ended March 31, 2014 and 2013:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2014	2013	2014	2013
Southeast Louisiana	$37.2	$44.1	400	446
South Texas	99.4	86.7	2,350	2,105
Central Louisiana	11.6	15.2	186	249
Other	0.4	0.5	8	19
Total	$148.6	$146.5	2,944	2,819

In the first quarter of 2014, our $2.1 million, or 1% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $6.0 million favorable impact on sales, with an increase of $11.4 million attributable to the 42% increase in natural gas prices, a decrease of $8.4 million due to the 8% decrease in average oil prices received and an increase of $3.0 million due to the 21% increase in NGL prices.
- Volume variances that had a $3.9 million unfavorable impact on sales, with a $6.2 million decrease due to a 0.1 million Bbl decrease in oil production volumes and a $2.3 million decrease attributable to the 0.1 million Bbl decrease in NGL production volumes, partially offset by a $4.6 million increase due to the 1.6 Bcf increase in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the three months ended March 31, 2014 and 2013:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended March 31, 2014	931	478	9.2	2,944	$99.38	$36.27	$4.20
Three Months Ended March 31, 2013	988	557	7.6	2,819	$108.45	$29.90	$2.96

For the three months ended March 31, 2014 and 2013, we recorded net losses of $5.1 million and $0.3 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $98.42 and $108.40 for the three months ended March 31, 2014 and 2013, respectively, and our average natural gas price would have been $3.75 and $2.93 for the three months ended March 31, 2014 and 2013, respectively.

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Costs and Expenses — Three Months Ended March 31, 2014 and 2013

Our expenses in the first quarter of 2014 decreased $2.6 million, or 2%, compared to those in the first quarter of 2013, for the reasons noted below.

Lease operating cost. These expenses decreased $2.2 million, or 8%, compared to the level of such expenses in the first quarter of 2013. The decrease was due to costs associated with a well control incident in Lake Washington during the first quarter of 2013 as well as cost decreases in South Texas for lower salt water disposal costs. Our lease operating costs per Boe produced were $8.58 and $9.73 for the three months ended March 31, 2014 and 2013, respectively.

Transportation and gas processing. These expenses decreased $0.7 million, or 12%, compared to the level of such expenses in the first quarter of 2013 as our NGL production volumes decreased 14%. Our transportation and gas processing costs per Boe produced were $1.80 and $2.14 for the three months ended March 31, 2014 and 2013, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $1.6 million, or 3% from those in the first quarter of 2013. The increase was due to higher production and a higher depletable base including higher future development costs, partially offset by higher reserve volumes. Our DD&A rate per Boe of production improved to $20.95 for the three months ended March 31, 2014, as compared to $21.33 for the three months ended March 31, 2013.

General and Administrative Expenses, Net. These expenses decreased $2.0 million, or 16%, from the level of such expenses in the first quarter of 2013. The decrease was primarily due to lower deferred compensation and a lower benefit accrual partially offset by lower capitalized amounts. For the first quarter of 2014, our capitalized general and administrative costs totaled $7.1 million and $9.1 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.65 per Boe in the first quarter of 2014 from $4.51 per Boe in the first quarter of 2013. The supervision fees recorded as a reduction to general and administrative expenses were $2.8 million for the three months ended March 31, 2014 and 2013.

Severance and Other Taxes. These expenses decreased $0.6 million, or 6%, from first quarter 2013 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.2% and 6.7% in the three months ended March 31, 2014 and 2013, respectively. The decrease in the rate was primarily driven by credits from reduced tax rates of gas production related to South Texas completions in prior period wells.

Interest. Our gross interest cost in the first quarter of 2014 was $19.7 million, of which $1.3 million was capitalized. Our gross interest cost in the first quarter of 2013 was $18.7 million, of which $1.9 million was capitalized. The increase came primarily from additional borrowings on our credit facility.

Income Taxes. Our effective income tax rate was 53.6% and 37.8% for the three months ended March 31, 2014 and 2013, respectively. This increase in rate related to a shortfall between the tax deduction received with respect to prior restricted stock grants that vested in the quarter versus the actual book expense recorded over the life of those grants.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the first three months of 2014, our net cash provided by operating activities was $69.7 million, representing a 12% increase compared to $62.2 million generated during the same period of 2013. The increase was mainly due to changes in working capital.

Working Capital and Debt to Capitalization Ratio. Our working capital increased from a deficit of $90.3 million at December 31, 2013, to a deficit of $75.2 million at March 31, 2014. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our working capital ratio does not include available liquidity through our credit facility. Our debt to capitalization ratio was 53% at March 31, 2014 and December 31, 2013.

Existing Credit Facility. Our borrowing base was reaffirmed at $450.0 million as of April 30, 2014. The next scheduled borrowing base redetermination occurs in November 2014. At March 31, 2014, we had $297.7 million in outstanding borrowings under our credit facility. Our available borrowings under our credit facility provide us liquidity along with any proceeds received from asset sales. In light of credit market volatility in recent years, which caused many financial institutions to experience liquidity issues, we periodically review the creditworthiness of the banks that fund our credit facility.

Asset Dispositions and Joint Ventures. We plan to utilize amounts received from any joint ventures and/or asset sales entered into during 2014 to strengthen our balance sheet, and potentially fund a portion of our 2014 capital expenditures. As

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previously noted; we are currently engaged in negotiations regarding a joint venture arrangement related to our Fasken Eagle Ford acreage and the potential sale of some or all of our Central Louisiana assets with prospective buyers. The completion of one or both of these transactions will affect the level of our 2014 capital expenditures as we better align our capital expenditures with our expected cash flows. Either or both transactions discussed above would initially reduce the borrowing base on our line of credit, but would also lower our leverage and enhance our liquidity, given that the expected proceeds would exceed any associated borrowing base reduction.

Contractual Commitments and Obligations

We had no other material changes in our contractual commitments and obligations from amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ending December 31, 2013.

Critical Accounting Policies and New Accounting Pronouncements

Property and Equipment. We follow the "full-cost" method of accounting for oil and natural gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the exploration, development, and acquisition of oil and natural gas reserves are capitalized including internal costs incurred that are directly related to these activities and which are not related to production, general corporate overhead, or similar activities. Future development costs are estimated property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized. We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method.

The costs of unproved properties not being amortized are assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. As these factors may change from period to period, our evaluation of these factors will change. Any impairment assessed is added to the cost of proved properties being amortized.

The calculation of the provision for DD&A requires us to use estimates related to quantities of proved oil and natural gas reserves and estimates of unproved properties. For both reserves estimates (see discussion below) and the impairment of unproved properties (see discussion above), these processes are subjective, and results may change over time based on current information and industry conditions. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Full-Cost Ceiling Test. At the end of each quarterly reporting period, the unamortized cost of oil and natural gas properties (including natural gas processing facilities, capitalized asset retirement obligations and deferred income taxes, and excluding the recognized asset retirement obligation liability) is limited to the sum of the estimated future net revenues from proved properties (excluding cash outflows from recognized asset retirement obligations, including future development and abandonment costs of wells to be drilled, using the preceding 12-months' average price based on closing prices on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects ("Ceiling Test").

We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near-term. If oil and natural gas prices decline from the prices used in the Ceiling Test, even if only for a short period, it is reasonably possible that non-cash write-downs of oil and gas properties would occur in the future. If future capital expenditures out pace future discounted net cash flows in our reserve calculations or if we have significant declines in our oil and natural gas reserves volumes, which also reduces our estimate of discounted future net cash flows from proved oil and natural gas reserves, non-cash write-downs of our oil and natural gas properties would occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties if a decrease in oil and/or natural gas prices were to occur.

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of March 31, 2014.

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Forward-Looking Statements

This report includes forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. 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 included in this report, regarding our strategy, future operations, financial position, estimated production levels, reserve increases, capital expenditures, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," “budgeted”, "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.

Forward-looking statements may include statements about our:

- business strategy;
- estimated oil and natural gas reserves or the present value thereof;
- technology;
- our borrowing capacity, cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- asset disposition efforts or the timing or outcome thereof;
- prospective joint ventures, their structure and substance, and the likelihood of their finalization or the timing thereof;
- oil and natural gas pricing expectations;
- the amount, nature and timing of capital expenditures, including future development costs;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment or availability of oil field labor;
- availability and terms of capital;
- drilling of wells;
- marketing and transportation of oil and natural gas;
- costs of exploiting and developing our properties and conducting other operations;
- competition in the oil and natural gas industry;
- general economic conditions;
- opportunities to monetize assets;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in world oil markets and in oil and natural gas-producing countries;
- uncertainty regarding our future operating results;
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. 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. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2013. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

All subsequent written and oral forward-looking statements attributable to us or to persons acting on our behalf are expressly qualified in their entirety by the foregoing. We undertake no obligation to publicly release the results of any revisions to any such forward-looking statements that may be made to reflect events or circumstances after the date of this report or to reflect the occurrence of unanticipated events.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. This commodity pricing volatility has continued with unpredictable price swings throughout 2013 and into 2014.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. For additional discussion related to our price-risk management policy, refer to Note 2 of these condensed consolidated financial statements.

Customer Credit Risk. We are exposed to the risk of financial non-performance by customers. Our ability to collect on sales to our customers is dependent on the liquidity of our customer base. Continued volatility in both credit and commodity markets may reduce the liquidity of our customer base. To manage customer credit risk, we monitor credit ratings of customers and from certain customers we also obtain letters of credit, parent company guaranties if applicable, and other collateral as considered necessary to reduce risk of loss. Due to availability of other purchasers, we do not believe the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations.

Concentration of Sales Risk. Over the last several years, a large portion of our oil and gas sales have been to Shell Oil Corporation and affiliates and we expect to continue this relationship in the future. We believe that the risk of these unsecured receivables is mitigated by the short-term sales agreements we have in place as well as the size, reputation and nature of their business.

Interest Rate Risk. Our senior notes due in 2017, 2020 and 2022 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At March 31, 2014, we had $297.7 million drawn under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our future cash flows.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, consisting of controls and other procedures designed to give reasonable assurance that information we are required to disclose in the reports we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and that such information is accumulated and communicated to management, including our chief executive officer and our chief financial officer, to allow timely decisions regarding such required disclosure. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first three months of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

No material legal proceedings are pending other than ordinary, routine litigation incidental to the Company's business.

Item 1A. Risk Factors.

There have been no material changes in our risk factors from those disclosed in our 2013 Annual Report on Form 10-K.

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

The following table summarizes repurchases of our common stock occurring during the first quarter of 2014:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
01/01/14 – 01/31/14 (1)	874	$ 13.08	—	$—
02/01/14 – 02/28/14 (1)	69,706	$ 12.02	—	—
03/01/14 – 03/31/14 (1)	532	$ 9.73	—	—
Total	71,112	$ 12.02	—	$—

(1) These shares were withheld from employees to satisfy tax obligations arising upon the vesting of restricted shares.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

None.

Item 5. Other Information.

On April 30, 2014, Swift Energy Company and its wholly-owned subsidiary, Swift Energy Operating, LLC, entered into the Fourth Amendment to the Second Amended and Restated Credit Agreement dated as of September 21, 2010, as amended by the First Amendment and Consent dated as of May 12, 2011, and the Second Amendment dated as of October 2, 2012, with JPMorgan Chase Bank, N.A., as Administrative Agent, and institutions named therein as lenders (the "Amendment"). The Amendment re-affirms the Company's borrowing base at $450 million, and Swift Energy elected to retain its commitment amount at $450 million. The Amendment also modifies an existing negative covenant to allow the Company to enter hedging agreements with approved counterparties, as defined in the Amendment.

Item 6. Exhibits.

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31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*Filed herewith

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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.

		SWIFT ENERGY COMPANY (Registrant)
Date:	May 1, 2014	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President Chief Financial Officer and Principal Accounting Officer

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