SWIFT ENERGY CO
Form 10-Q
November 05, 2015

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

FORM 10-Q

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

For the quarterly period ended September 30, 2015
Commission File Number 1-8754
SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

Texas	20-3940661
(State of Incorporation)	(I.R.S. Employer Identification No.)

17001 Northchase Drive, Suite 100
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

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, and (2) has been subject to such filing requirements for the past 90 days.
Yes þ 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act.
Large accelerated filer þ 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 o No þ

Indicate the number of shares outstanding of each of the Issuer’s classes
of common stock, as of the latest practicable date.

Common Stock ($.01 Par Value) (Class of Stock)	44,550,975 Shares (Outstanding at October 31, 2015)

1

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2015
INDEX

		Page
Part I	FINANCIAL INFORMATION	
Item 1.	Condensed Consolidated Financial Statements	
	Condensed Consolidated Balance Sheets	3
	Condensed Consolidated Statements of Operations	4
	Condensed Consolidated Statements of Stockholders' Equity	5
	Condensed Consolidated Statements of Cash Flows	6
	Notes to Condensed Consolidated Financial Statements	7
Item 2.	Management's Discussion and Analysis of Financial Condition and Results of Operations	21
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	33
Item 4.	Controls and Procedures	34
Part II	OTHER INFORMATION	
Item 1.	Legal Proceedings	35
Item 1A.	Risk Factors	35
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	35
Item 3.	Defaults Upon Senior Securities	36
Item 4.	Mine Safety Disclosures	36
Item 5.	Other Information	36
Item 6.	Exhibits	37
SIGNATURES		38
Exhibit Index		39

Table of Contents

Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current Assets:		
Cash and cash equivalents	$7,322	$406
Accounts receivable	36,610	48,451
Deferred tax asset	—	6,243
Other current assets	4,299	9,569
Total Current Assets	48,231	64,669
Property and Equipment:		
Property and Equipment, including $69,697 and $64,903 of unproved property costs not being amortized, respectively	6,023,634	5,934,155
Less – Accumulated depreciation, depletion, and amortization	(5,061,058)	(3,839,118)
Property and Equipment, Net	962,576	2,095,037
Other Long-Term Assets	13,471	13,641
Total Assets	$1,024,278	$2,173,347
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$49,116	$68,244
Accrued capital costs	19,509	41,461
Accrued interest	13,783	21,389
Undistributed oil and gas revenues	12,589	17,825
Total Current Liabilities	94,997	148,919
Long-Term Debt	1,179,132	1,074,534
Deferred Tax Liabilities	—	86,376
Asset Retirement Obligation	65,448	62,122
Other Long-Term Liabilities	9,511	7,018
Commitments and Contingencies	—	—
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 150,000,000 shares authorized, 44,709,758 and 44,379,463 shares issued, and 44,547,481 and 43,918,029 shares outstanding, respectively	447	444
Additional paid-in capital	774,830	771,972
Treasury stock held, at cost, 162,277, and 461,434 shares, respectively	(2,487)	(9,855)
Retained earnings (Accumulated deficit)	(1,097,600)	31,817
Total Stockholders' Equity (Deficit)	(324,810)	794,378
Total Liabilities and Stockholders' Equity	$1,024,278	$2,173,347

See accompanying Notes to Condensed Consolidated Financial Statements.

3

Table of Contents

Condensed Consolidated Statements of Operations (Unaudited)
Swift Energy Company and Subsidiaries (in thousands, except per-share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues:				
Oil and gas sales	$60,024	$133,896	$195,663	$441,440
Price-risk management and other, net	92	4,898	(1,041)	(2,472)
Total Revenues	60,116	138,794	194,622	438,968
Costs and Expenses:				
General and administrative, net	8,679	10,981	31,525	33,565
Depreciation, depletion, and amortization	35,606	65,331	138,392	201,072
Accretion of asset retirement obligation	1,410	1,445	4,156	4,246
Lease operating cost	17,990	22,067	54,188	70,606
Transportation and gas processing	5,446	5,107	15,855	16,412
Severance and other taxes	4,613	10,191	14,169	28,829
Interest expense, net	19,438	18,197	56,407	55,295
Write-down of oil and gas properties	321,522	—	1,084,595	—
Total Costs and Expenses	414,704	133,319	1,399,287	410,025
Income (Loss) Before Income Taxes	(354,588)	5,475	(1,204,665)	28,943
Provision (Benefit) for Income Taxes	—	3,001	(80,133)	14,200
Net Income (Loss)	$(354,588)	$2,474	$(1,124,532)	$14,743
Per Share Amounts-				
Basic: Net Income (Loss)	$(7.96)	$0.06	$(25.31)	$0.34
Diluted: Net Income (Loss)	$(7.96)	$0.06	$(25.31)	$0.33
Weighted Average Shares Outstanding - Basic	44,546	43,850	44,431	43,768
Weighted Average Shares Outstanding - Diluted	44,546	44,473	44,431	44,299

See accompanying Notes to Condensed Consolidated Financial Statements.

Table of Contents

Condensed Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings (Accumulated Deficit)	Total
Balance, December 31, 2013	$439	$762,242	$(12,575)	$315,244	$1,065,350
Stock issued for benefit plans (154,665 shares)	—	(1,876)	3,785	—	1,909
Purchase of treasury shares (102,673 shares)	—	—	(1,065)	—	(1,065)
Employee stock purchase plan (71,825 shares)	1	823	—	—	824
Issuance of restricted stock (392,292 shares)	4	(4)	—	—	—
Amortization of share-based compensation	—	10,787	—	—	10,787
Net Loss	—	—	—	(283,427)	(283,427)
Balance, December 31, 2014	$444	$771,972	$(9,855)	$31,817	$794,378
Stock issued for benefit plans (352,476 shares) (1)	—	(1,714)	7,518	(4,885)	919
Purchase of treasury shares (53,319 shares) (1)	—	—	(150)	—	(150)
Employee stock purchase plan (87,629 shares) (1)	1	301	—	—	302
Issuance of restricted stock (242,666 shares) (1)	2	(2)	—	—	—
Amortization of share-based compensation (1)	—	4,273	—	—	4,273
Net Loss (1)	—	—	—	(1,124,532)	(1,124,532)
Balance, September 30, 2015 (1)	$447	$774,830	$(2,487)	$(1,097,600)	$(324,810)

(1) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

Table of Contents

Condensed Consolidated Statements of Cash Flows (Unaudited)
Swift Energy Company and Subsidiaries (in thousands)

	Nine Months Ended September 30,	
	2015	2014
Cash Flows from Operating Activities:		
Net income (loss)	$(1,124,532)	$14,743
Adjustments to reconcile net income (loss) to net cash provided by operating activities-		
Depreciation, depletion, and amortization	138,392	201,072
Write-down of oil and gas properties	1,084,595	—
Accretion of asset retirement obligation	4,156	4,246
Deferred income taxes	(80,133)	13,507
Share-based compensation expense	3,288	5,571
Other	3,627	(390)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable and other current assets	11,841	14,159
Increase (decrease) in accounts payable and accrued liabilities	(4,768)	7,299
Increase (decrease) in income taxes payable	(450)	543
Increase (decrease) in accrued interest	(7,606)	(8,575)
Net Cash Provided by Operating Activities	28,410	252,175
Cash Flows from Investing Activities:		
Additions to property and equipment	(126,752)	(316,972)
Proceeds from the sale of property and equipment	977	145,535
Funds withdrawn from restricted cash account	—	6,501
Funds deposited into restricted cash account	—	(18,345)
Net Cash Used in Investing Activities	(125,775)	(183,281)
Cash Flows from Financing Activities:		
Proceeds from bank borrowings	258,200	356,900
Payments of bank borrowings	(153,500)	(419,900)
Net proceeds from issuances of common stock	302	824
Purchase of treasury shares	(150)	(954)
Payments of debt issuance costs	(571)	—
Net Cash Provided by (Used in) Financing Activities	104,281	(63,130)
Net increase in Cash and Cash Equivalents	6,916	5,764
Cash and Cash Equivalents at Beginning of Period	406	3,277
Cash and Cash Equivalents at End of Period	$7,322	$9,041
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$62,012	$61,983
Cash paid during period for income taxes	$450	$150

See accompanying Notes to Condensed Consolidated Financial Statements.

6

Table of Contents

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries

(1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company ("Swift Energy," the "Company," or "we") and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission. We believe that the disclosures presented are adequate to allow the information presented not to be misleading. The condensed consolidated financial statements should be read in conjunction with the audited financial statements and the notes thereto included in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014 as filed with the Securities and Exchange Commission on March 2, 2015.

(2) Summary of Significant Accounting Policies

Principles of Consolidation. The accompanying condensed consolidated financial statements include the accounts of Swift Energy and its wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and gas properties, with a focus on inland waters and onshore oil and natural gas reserves in Louisiana and Texas. Our undivided interests in oil and gas properties are accounted for using the proportionate consolidation method, whereby our proportionate share of each entity's assets, liabilities, revenues, and expenses are included in the appropriate classifications in the accompanying condensed consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the accompanying condensed consolidated financial statements.

Subsequent Events. On November 2, 2015 we executed an amendment to our credit facility decreasing our borrowing base and commitment amount on our credit facility, changing certain of our financial covenant ratios, and providing for a borrowing base redetermination on or about February 1, 2016 if we have not reduced the current outstanding principal amount of our unsecured or subordinated debt by at least 50% by that date, along with other changes detailed in Note 5 of these condensed consolidated financial statements. There were no other material subsequent events requiring additional disclosure in these financial statements.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("GAAP") requires us to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. 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. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties , the related present value of estimated future net cash flows there-from, and the ceiling test impairment calculation,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation of share-based compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,

- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations,
- estimates in the calculation of the fair value of hedging assets and liabilities, and
- estimates in the assessment of current litigation claims against the company.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts, joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many

Table of Contents

of which require retroactive application. These types of adjustments cannot be currently estimated and will be recorded in the period during which the adjustments occur.

We are subject to legal proceedings, claims, liabilities and environmental matters that arise in the ordinary course of business. We accrue for losses when such losses are considered probable and the amounts can be reasonably estimated.

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. Such costs may be incurred both prior to and after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, and equipment. Internal costs incurred that are directly identified with exploration, development, and acquisition activities undertaken by us for our own account, and which are not related to production, general corporate overhead, or similar activities, are also capitalized. For the three months ended September 30, 2015 and 2014, such internal costs capitalized totaled $3.1 million and $6.9 million, respectively. For the nine months ended September 30, 2015 and 2014, such internal costs capitalized totaled $10.1 million and $20.9 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 5 of these consolidated financial statements for further discussion on capitalized interest costs).

The "Property and Equipment" balances on the accompanying condensed consolidated balance sheets are summarized for presentation purposes. The following is a detailed breakout of our "Property and Equipment" balances:

(in thousands)	September 30, 2015	December 31, 2014
Property and Equipment		
Proved oil and gas properties	$5,910,250	$5,826,995
Unproved oil and gas properties	69,697	64,903
Furniture, fixtures, and other equipment	43,687	42,257
Less – Accumulated depreciation, depletion, and amortization	(5,061,058)	(3,839,118)
Property and Equipment, Net	$962,576	$2,095,037

No gains or losses are recognized upon the sale or disposition of oil and natural gas properties, except in transactions involving a significant amount of reserves or where the proceeds from the sale of oil and natural gas properties would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a cost center. Internal costs associated with selling properties are expensed as incurred.

Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized to expense as our capitalized oil and 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. Under this method, we compute the provision by multiplying the total unamortized costs of oil and gas properties-including future development costs, gas processing facilities, and both capitalized asset retirement obligations and undiscounted abandonment costs of wells to be drilled, net of salvage values, but excluding costs of unproved properties-by an overall rate determined by dividing the physical units of oil and natural gas produced (which excludes natural gas consumed in operations) during the period by the total estimated units of proved oil and natural gas reserves (which excludes natural gas consumed in operations) at the beginning of the period. This calculation is done on a country-by-country basis and the period over which we will amortize these properties is dependent on our production from these properties in future years. Furniture, fixtures, and other equipment are recorded at cost and are depreciated by the straight-line method at rates based on the estimated useful lives of the property, which range between two and 20 years. Repairs and maintenance are charged to expense as incurred.

Geological and geophysical (“G&G”) costs incurred on developed properties are recorded in “Proved properties” and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in “Unproved properties” and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is 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. Any impairment assessed is added to the cost of proved properties being amortized.

Table of Contents

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, net of related salvage values 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").

The calculations of the Ceiling Test and provision for DD&A are based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimates. Accordingly, reserves estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, for the three and nine months ended September 30, 2015, we reported a non-cash impairment write-down, on a before-tax basis, of $321.5 million and $1.1 billion, respectively, on our oil and natural gas properties.

If future capital expenditures out pace future discounted net cash flows in our reserve calculations, 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) or if oil or natural gas prices decline or remain at levels prevalent in the current period, it is likely that non-cash write-downs of our oil and natural gas properties will 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 due to decreases in oil or natural gas prices. However, due to current trends in commodity pricing it is likely that we will record additional ceiling test write-downs in future periods.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of September 30, 2015 and December 31, 2014, we did not have any material natural gas imbalances.

Reclassification of Prior Period Balances. Certain reclassifications have been made to prior period amounts to conform to the current-year presentation.

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At September 30, 2015 and December 31, 2014, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At September 30, 2015, our "Accounts receivable" balance included $22.6 million for oil and gas sales, $9.6 million for joint interest owners, $3.4 million for severance tax credit receivables and $1.0 million for other receivables. At December 31, 2014, our "Accounts receivable" balance included $34.8 million for oil and gas sales, $8.4 million for joint interest owners, $3.1 million for severance tax credit receivables and $2.2 million for other receivables.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate, including our wells, in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to “General and administrative, net”, on the accompanying condensed consolidated statements of operations. Our supervision fees are allocated to each well based on general and administrative costs incurred for well maintenance and support. The amount of supervision fees charged for the three and nine months ended September 30, 2015 and 2014 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated were $2.1 million and $3.5 million for the three months ended September 30, 2015 and 2014, respectively and $7.0 million and $9.2 million for the nine months ended September 30, 2015 and 2014, respectively.

Other Current Assets. Included in "Other current assets" on the accompanying condensed consolidated balance sheets are inventories which consist primarily of tubulars and other equipment and supplies that we expect to place in service in production

Table of Contents

operations. Our inventories are recorded at cost (weighted average method) and totaled $0.9 million at September 30, 2015 and $3.1 million at December 31, 2014.

Also included in "Other current assets" on the accompanying condensed consolidated balance sheets are prepaid expenses totaling $3.1 million and $3.9 million at September 30, 2015 and December 31, 2014, respectively. These prepaid amounts cover well insurance, drilling contracts and various other prepaid expenses.

Income Taxes. Under guidance contained in FASB ASC 740-10, deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of the enacted tax laws.

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At September 30, 2015, we did not have any accrued liability for uncertain tax positions and do not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

Our U.S. Federal income tax returns for 2007 forward, our Louisiana income tax returns from 1999 forward and our Texas franchise tax returns after 2009 remain subject to examination by the taxing authorities. There are no material unresolved items related to periods previously audited by these taxing authorities. No other jurisdiction returns are significant to our financial position.

For the three months ended September 30, 2015, the tax benefit for the book loss was fully offset with an increase in our valuation allowance against our deferred tax assets. For the nine months ended September 30, 2015, the tax benefit for the book loss was mostly offset with an increase in our valuation allowance against our deferred tax assets.

Accounts Payable and Accrued Liabilities. The “Accounts payable and accrued liabilities” balances on the accompanying condensed consolidated balance sheets are summarized below (in thousands):

	September 30, 2015	December 31, 2014
Trade accounts payable (1)	$ 17,600	$ 31,153
Accrued operating expenses	8,134	10,784
Accrued compensation costs	7,064	8,715
Asset retirement obligation – current portion	7,124	10,709
Accrued taxes	5,652	2,957
Other payables	3,542	3,926
Total accounts payable and accrued liabilities	$ 49,116	$ 68,244

(1) Included in “trade accounts payable” are liabilities of approximately $2.2 million and $13.7 million at September 30, 2015 and December 31, 2014, respectively, for outstanding checks.

Cash and Cash Equivalents. We consider all highly liquid instruments with an initial maturity of three months or less to be cash equivalents. These amounts do not include cash balances that are contractually restricted.

Saka Energi Transaction. On July 15, 2014, we closed our transaction with PT Saka Energi Indonesia ("Saka Energi") to fully develop 8,300 acres of Fasken area Eagle Ford shale properties owned by Swift Energy in Webb County, Texas. Swift Energy sold a 36% full participating interest in the Fasken properties to Saka Energi. Subject to the terms of the transaction, Swift Energy and Saka Energi were required to deposit cash on a monthly basis into a separate

Swift Energy-owned bank account to fund their respective portions of the on-going Fasken development program for the following month.

During the third quarter of 2014, cash deposited in the account was contractually restricted for use in the Fasken development program and therefore was recorded as restricted cash until the Company had performed the related development activities. The cash changes from the account during the third quarter of 2014 relating to Saka Energi's contributions were shown in the operating activities section of the accompanying condensed consolidated statements of cash flows. The cash changes from

Table of Contents

the account during the third quarter of 2014 relating to Swift Energy's contributions were reported in the investing activities section on the accompanying condensed consolidated statements of cash flows.

Long-term Restricted Cash. Long-term restricted cash includes amounts held in escrow accounts to satisfy plugging and abandonment obligations. As of September 30, 2015 and December 31, 2014, these assets were approximately $1.0 million. These amounts are restricted as to their current use and will be released when we have satisfied all plugging and abandonment obligations in certain fields. These restricted cash balances are reported in "Other Long-Term Assets" on the accompanying condensed consolidated balance sheets.

Treasury Stock. Our treasury stock repurchases are reported at cost and are included "Treasury stock held, at cost" on the accompanying condensed consolidated balance sheets. When the Company reissues treasury stock the gains are recorded in "Additional paid-in capital" ("APIC") on the accompanying condensed consolidated balance sheets, while the losses are recorded to APIC to the extent that previous net gains on the reissuance of treasury stock are available to offset the losses. If the loss is larger than the previous gains available then the loss is recorded to "Retained earnings (Accumulated deficit)" on the accompanying condensed consolidated balance sheets. For the nine months ended September 30, 2015, the Company recorded losses of $4.9 million to "Retained earnings (Accumulated deficit)" as a result of treasury stock transactions.

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09, providing a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance. The guidance requires entities to recognize revenue using the following five-step model: identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract, and recognize revenue as the entity satisfies each performance obligation. Adoption of this standard could result in retrospective application, either in the form of recasting all prior periods presented or a cumulative adjustment to equity in the period of adoption. The guidance is effective for annual and interim reporting periods beginning after December 15, 2017. We are currently reviewing the new requirements to determine the impact of this guidance on our financial statements.

In April 2015, the FASB issued ASU 2015-03, providing guidance on the presentation of debt issuance costs. The guidance requires debt issuance costs related to our long-term debt to be presented on the balance sheet as a reduction of the carrying amount of the long-term debt. This guidance is effective for fiscal years beginning after December 15, 2015 and for interim periods within those fiscal years, with early adoption permitted and retrospective application required. This guidance, which we plan to adopt beginning with the first quarter of 2016, is not expected to have a material impact on our financial statements.

In July 2015, the FASB issued ASU 2015-11, which changes the measurement principle for inventory from the lower of cost or market to "lower of cost and net realizable value." The standard simplifies the current guidance under which an entity must measure inventory at the lower of cost or market (market in this context is defined as one of three different measures, one of which is net realizable value). Net realizable value is defined as the "estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation." The guidance is effective for fiscal years beginning after December 15, 2016, including interim periods thereafter, and must be applied prospectively after the date of adoption. We are currently reviewing the new requirement to determine the impact of this guidance on our financial statements.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to our definitive proxy statement for our annual meeting of shareholders filed with the SEC on April 2, 2015, as well as Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014, for additional information related to these share-based compensation plans. We follow guidance contained in FASB ASC 718 to account for share-based compensation.

We receive a tax deduction for certain stock option exercises during the period the stock options are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards. We receive an additional tax deduction when restricted stock awards vest at a higher value than the value used to recognize compensation expense at the date of grant. We are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the three months ended September 30, 2015, there was no income tax shortfall in earnings, while for the three months ended September 30, 2014 we did recognize an income tax shortfall in earnings of $0.2 million. For the nine months ended September 30, 2015 and 2014, we recognized an income tax shortfall in earnings of $1.4 million and $2.1 million, respectively, primarily related to restricted stock awards that vested at a price lower than the grant date fair value.

Share-based compensation expense for awards issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations, was $1.1 million and

Table of Contents

$1.7 million for the three months ended September 30, 2015 and 2014, respectively, and $3.1 million and $5.1 million for the nine months ended September 30, 2015 and 2014, respectively. Share-based compensation recorded in lease operating cost was less than $0.1 million for the three months ended September 30, 2015 and 2014 and $0.1 million and $0.2 million for the nine months ended September 30, 2015 and 2014, respectively. We also capitalized $0.4 million and $0.9 million of share-based compensation for the three months ended September 30, 2015 and 2014, respectively, and capitalized $1.0 million and $2.9 million for the nine months ended September 30, 2015 and 2014, respectively. We view stock option awards and restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life of component awards, and we amortize the awards on a straight-line basis over the life of the awards.

Stock Option Awards

We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards. During the nine months ended September 30, 2015, 1,800 stock option awards expired leaving 1,330,390 stock option awards outstanding at September 30, 2015. There was no other activity relating to our stock option awards during the nine months ended September 30, 2015.

As of September 30, 2015, our stock option awards outstanding and exercisable had no aggregate intrinsic value since all outstanding stock option awards were out of the money, and we did not have any remaining unrecognized compensation cost related to stock option awards. At September 30, 2015, the weighted average contract life of stock option awards outstanding and exercisable was 4.0 years.

Restricted Stock Awards

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2014, allow for the issuance of restricted stock awards that generally may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2015, we had unrecognized compensation expense of $4.9 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.4 years. The grant date fair value of shares vested during the nine months ended September 30, 2015 was $5.3 million.

The following table represents restricted stock award activity for the nine months ended September 30, 2015:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	1,414,012	$14.81
Restricted shares granted	609,238	$2.64
Restricted shares canceled	(222,057)	$13.84
Restricted shares vested	(242,567)	$21.66
Restricted shares outstanding, end of period	1,558,626	$9.12

Performance-Based Restricted Stock Units

For the nine months ended September 30, 2015, the Company granted 216,450 units of performance-based restricted stock units containing market conditions that require the price of our common stock to increase to $5.22 per share by December 31, 2017, the end of the performance period, before any payout is achieved. These units were granted at

100% of the target payout level with conditions of the grants allowing for a payout ranging between no payout and 200% of target. The compensation expense for these awards is based on the per unit grant date valuation using a Monte-Carlo simulation multiplied by the target payout level. The payout level is calculated based on actual stock price performance achieved during the performance period. The awards have a cliff vesting period of 3.0 years.

As of September 30, 2015, we had unrecognized compensation expense of $1.1 million related to our restricted stock units, which is expected to be recognized over a weighted-average period of 1.6 years. No shares vested during the nine months

Table of Contents

ended September 30, 2015 and 2014. The weighted average grant date fair value for the restricted stock units granted during the nine months ended September 30, 2015 was $1.98 per unit.

The following table represents restricted stock unit activity for the nine months ended September 30, 2015:

	Shares	Wtd. Avg. Grant Price
Restricted stock units outstanding, beginning of period	374,950	$ 13.36
Restricted stock units granted	216,450	$ 1.98
Restricted stock units canceled	—	$ —
Restricted stock units vested	—	$ —
Restricted stock units outstanding, end of period	591,400	$ 9.20

Cash-Settled Restricted Stock Units (Liability Awards)

During the nine months ended September 30, 2015, the Company granted 147,812 units of cash-settled restricted stock units. These grants require a cash payout based on the fair value of the stock price on the date of the next Annual Shareholder Meeting in May of 2016. The grants have a cliff vesting period of approximately 1.0 year while the compensation expense and corresponding liability are remeasured quarterly over the corresponding service period. The Company recorded a liability of less than $0.1 million for these awards in "Accounts Payable and accrued liabilities" on the accompanying condensed consolidated balance sheet as of September 30, 2015.

(4) Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. Diluted earnings per share ("Diluted EPS") assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Diluted EPS also assumes conversion of performance-based restricted stock units to common shares based on the number of shares (if any) that would be issuable, according to predetermined performance and market goals, if the end of the reporting period was the end of the performance period. As we recognized a net loss for the three and nine months ended September 30, 2015, the unvested share-based payments and stock options were not recognized in diluted earnings per share ("Diluted EPS") calculations as they would be antidilutive. Certain of our stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the three and nine months ended September 30, 2014, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and nine months ended September 30, 2015 and 2014 (in thousands, except per share amounts):

	Three Months Ended September 30, 2015			Three Months Ended September 30, 2014		
	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$ (354,588)	44,546	$ (7.96)	$ 2,474	43,850	$ 0.06
Dilutive Securities:						
Restricted Stock Awards		—			564	
Restricted Stock Units		—			59	
Diluted EPS:						
	$ (354,588)	44,546	$ (7.96)	$ 2,474	44,473	$ 0.06

Net Income (Loss) and Assumed Share Conversions

13

Table of Contents

	Nine Months Ended September 30, 2015			Nine Months Ended September 30, 2014		
	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	$(1,124,532)	44,431	$(25.31)	$14,743	43,768	$0.34
Dilutive Securities:						
Restricted Stock Awards		—			469	
Restricted Stock Units		—			62	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	$(1,124,532)	44,431	$(25.31)	$14,743	44,299	$0.33

Approximately 1.3 million and 1.4 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended September 30, 2015 and 2014 because they were antidilutive. We also had approximately 1.3 million and 1.4 million stock options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2015 and 2014, because these stock options were antidilutive.

Approximately 1.0 million and 0.2 million restricted stock awards for the three months ended September 30, 2015 and 2014, respectively, and approximately 0.8 million and 0.3 million restricted stock awards for the nine months ended September 30, 2015 and 2014, respectively, were not included in the computation of Diluted EPS because they were antidilutive.

Approximately 1.2 million and 0.7 million shares for the three months ended September 30, 2015 and 2014, respectively, and approximately 1.2 million and 0.7 million shares for the nine months ended September 30, 2015 and 2014, respectively, related to performance-based restricted stock units that could be converted to common shares based on predetermined performance and market goals were not included in the computation of Diluted EPS because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the performance period.

(5) Long-Term Debt

Our long-term debt as of September 30, 2015 and December 31, 2014, was as follows (in thousands):

	September 30, 2015	December 31, 2014
7.125% senior notes due in 2017	$250,000	$250,000
8.875% senior notes due in 2020 (1)	223,043	222,775
7.875% senior notes due in 2022 (1)	404,089	404,459
Bank Borrowings due in 2017	302,000	197,300
Long-Term Debt (1)	$1,179,132	$1,074,534

(1) Amounts are shown net of any debt discount or premium

As of September 30, 2015, we had $302.0 million of outstanding bank borrowings on our credit facility which has a maturity date of November 1, 2017. The maturities on our senior notes are $250.0 million in 2017, $225.0 million in 2020 and $400.0 million in 2022.

We had capitalized interest on our unproved properties in the amount of $1.2 million for the three months ended September 30, 2015 and 2014, respectively. We had capitalized interest on our unproved properties in the amount of $3.6 million and $3.7 million for the nine months ended September 30, 2015 and 2014, respectively.

Debt Issuance Costs. Legal fees, accounting fees, underwriting fees, printing costs, and other direct expenses associated with extensions of our bank credit facility and public debt offerings are capitalized and then amortized on an effective interest basis over the life of each of the respective senior note offerings and credit facility.

The 7.125% senior notes due in 2017 mature on June 1, 2017, and the balance of their issuance costs at September 30, 2015, was $0.9 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs

Table of Contents

at September 30, 2015, was $2.7 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at September 30, 2015, was $5.4 million. The balance of our revolving credit facility issuance costs at September 30, 2015, was $2.0 million.

Bank Borrowings. Effective November 2, 2015, we executed an amendment to our credit facility agreement lowering our borrowing base and commitment amount, changing our financial covenant ratios as noted below, and providing for a borrowing base redetermination on or about February 1, 2016 if we have not reduced the current outstanding principal amount of our unsecured or subordinated debt by at least 50% by that date, along with other changes detailed below. The borrowing base and commitment amount under our credit facility were decreased from $375.0 million to $330.0 million while the maturity date of November 1, 2017 remained unchanged, subject to being accelerated to March 2, 2017 if by that date the maturity dates of our existing Senior Notes are not extended to May 1, 2018 or later, or if those Senior Notes are not repurchased, redeemed or refinanced.

Effective November 2, 2015, the amendment made changes to the existing adjusted working capital ratio, interest coverage ratio and senior secured leverage ratio (all as defined in the Credit Agreement) and removed the existing liquidity requirement in order for us to pay interest on our existing senior notes or any new debt (after giving effect to such interest payment).

The adjusted working capital ratio was amended to require the ratio to not be less than 0.5 to 1.0 for each of the quarters up to and ending on December 31, 2016, returning to a ratio of not less than 1.0 to 1.0 at any time thereafter.

The interest coverage ratio was amended to require the ratio to not be less than 1.15 to 1.0 for the quarters ending on December 31, 2015 through June 30, 2016, 1.3 to 1.0 for the quarters ending September 30, 2016 through December 31, 2016, and 2.0 to 1.0 any time thereafter.

The senior secured leverage ratio was amended to require the ratio to not be greater than 3.5 to 1.0 for the quarters ending December 31, 2015 through June 30, 2016, 3.0 to 1.0 for the quarters ending September 30, 2016 through December 31, 2016, and 2.5 to 1.0 any time thereafter. The amendment also modified other requirements as noted in the paragraphs below. Based upon our current estimates of production and current commodity futures prices, our ability to remain in compliance with these modified financial covenant ratios in future periods is uncertain and will be impacted by a number of factors, including those which are not within our control.

Since inception, no cash dividends have been declared on our common stock. As of September 30, 2015, the terms of the credit facility required us to secure the facility with collateral equal to at least 75% (increasing to 95%, effective November 2, 2015) of our oil and natural gas properties. Under the terms of the credit facility, the commitment amount can be less than or equal to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. As of September 30, 2015, we were in compliance with these provisions.

We had $302.0 million and $197.3 million in outstanding borrowings under our credit facility at September 30, 2015 and December 31, 2014, respectively. As of September 30, 2015, the interest rate on our credit facility was either (a) the lead bank’s prime rate plus an applicable margin or (b) the Eurodollar rate plus an applicable margin. However with respect to (a), if the lead bank’s prime rate was not higher than each of the federal funds rate plus 0.5%, and the adjusted London Interbank Offered Rate (“LIBOR”) plus 1%, the greatest of these three rates then applied. The applicable margins vary depending on the level of outstanding debt with escalating rates of 75 to 175 basis points (increasing to 100 to 200 basis points effective November 2, 2015) above the Alternative Base Rate and escalating rates of 175 to 275 basis points (increasing to 200 to 300 basis points effective November 2, 2015) for Eurodollar rate loans. At September 30, 2015, the lead bank's prime rate was 3.25%. The commitment fee terms associated with the credit facility were 0.50% for the three months ended September 30, 2015.

At September 30, 2015, the terms of our credit facility included, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, and limitations on incurring other debt. At September 30, 2015, our bank credit agreement contained financial covenants detailing certain minimum financial ratios that must be maintained. The first was an adjusted working capital ratio of adjusted current assets to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0, which was met at September 30, 2015 as the Company's ratio at that date was 1.3 to 1.0. The second ratio was an interest coverage ratio (as amended on May 1, 2015), calculated on a trailing twelve month basis of EBITDAX to interest expense (as defined in the Credit Agreement), of no less than 1.5 to 1.0, which was met at September 30, 2015 as the Company's ratio at that date was 2.1 to 1.0. The third ratio was a new senior secured leverage ratio (as defined in the Credit Agreement, effective on May 1, 2015), requiring that the ratio of senior secured liabilities on the last day of the quarter to EBITDAX, calculated on a trailing twelve month basis, not be greater than 3.0 to 1.0, which was met as the Company's September 30, 2015 ratio was 2.0 to 1.0. The May 1, 2015 amendment also added a new liquidity requirement (as defined in the Credit Agreement) effective July 1, 2015 (and expiring on November 2, 2015 due

Table of Contents

to the most recent amendment) which effectively required that at the date of any payment of interest in respect to the existing senior notes or any new debt (after giving effect to such interest payment), the unused borrowing base may not be less than 15% of the commitment amount then in effect. We were in compliance with this covenant during the time period in which it was in effect.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $2.3 million and $1.7 million for the three months ended September 30, 2015 and 2014, respectively, and totaled $6.3 million and $5.9 million for the nine months ended September 30, 2015 and 2014, respectively. The amount of commitment fees included in interest expense, net was $0.1 million and $0.2 million for the three months ended September 30, 2015 and 2014, respectively, and was $0.5 million and $0.6 million for the nine months ended September 30, 2015 and 2014, respectively.

Senior Notes Due In 2022. These notes consist of $400.0 million of 7.875% senior notes that will mature on March 1, 2022. On November 30, 2011, we issued $250.0 million of these senior notes at a discount of $2.1 million or 99.156% of par, which equates to an effective yield to maturity of 8%. The original discount of $2.1 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. On October 3, 2012, we issued an additional $150.0 million of these senior notes at 105% of par, which equates to a yield to worst of 6.993%. The premium of $7.5 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on March 1 and September 1 and commenced on March 1, 2012. On or after March 1, 2017, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter. In addition, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $7.5 million of debt issuance costs related to these notes, which is included in "Other Long–Term Assets" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2015.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled $7.9 million for the three months ended September 30, 2015 and 2014 and $23.7 million for the nine months ended September 30, 2015 and 2014.

Senior Notes Due In 2020. These notes consist of $225.0 million of 8.875% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9.125%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on January 15, 2010. We may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. We incurred approximately $5.0 million of debt issuance costs related to these notes, which is included in “Other Long–Term Assets” on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2015.

Table of Contents

Interest expense on the senior notes due in 2020, including amortization of debt issuance costs and debt discount, totaled $5.2 million for the three months ended September 30, 2015 and 2014 and $15.6 million for the nine months ended September 30, 2015 and 2014.

Senior Notes Due In 2017. These notes consist of $250.0 million of 7.125% senior notes due in 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. We may redeem some or all of these notes, with certain restrictions, starting at a redemption price of 100% of the principal, plus accrued and unpaid interest. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2015.

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $4.6 million for the three months ended September 30, 2015 and 2014 and $13.7 million for the nine months ended September 30, 2015 and 2014, respectively.

(6) Acquisitions and Dispositions

On July 15, 2014, we closed our transaction with PT Saka Energi Indonesia ("Saka Energi") to fully develop 8,300 acres of Fasken area Eagle Ford shale properties owned by Swift Energy in Webb County, Texas. Swift Energy sold a 36% full participating interest in the Fasken properties to Saka Energi.

There were no other material acquisitions or dispositions in the nine months ended September 30, 2015 or 2014.

(7) Price-Risk Management Activities

The Company follows FASB ASC 815-10, which requires that changes in the derivative’s fair value are recognized in earnings. The changes in the fair value of our derivatives are recognized in "Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. We have a price-risk management policy to use derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price swaps, floors, calls, collars and participating collars.

During the three months ended September 30, 2015 and 2014, we recorded a net gain of less than of $0.1 million and a net gain of $5.0 million, respectively, and for the nine months ended September 30, 2015 and 2014, we recorded a net gain of $0.3 million and a net loss of $2.7 million, respectively, relating to our derivative activities. The effects of our derivatives are included in the "Other" section of our operating activities on the accompanying condensed consolidated statements of cash flows.

The fair values of our derivatives are computed using commonly accepted industry-standard models and are periodically verified against quotes from brokers. The fair value of our current unsettled derivative assets at September 30, 2015 was $0.1 million and was recognized on the accompanying condensed consolidated balance sheet in “Other current assets.” There were no material unsettled derivative liabilities as of September 30, 2015.

At September 30, 2015, we also had an immaterial amount of receivables for settled derivatives recognized on the accompanying condensed consolidated balance sheet in "Accounts receivable", which were subsequently received in October 2015.

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for our derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company has elected to not offset the asset and liability fair value amounts of its derivatives on the accompanying balance

Table of Contents

sheets. If all counterparties were in a default situation, the Company, under the right of set-off, would have shown a net derivative fair value asset of $0.1 million at September 30, 2015. For further discussion related to the fair value of the Company's derivatives, refer to Note 8 of these condensed consolidated financial statements.

The following tables summarize the weighted average prices and future production volumes for our unsettled derivative contracts in place as of September 30, 2015:

Natural Gas Basis Derivatives (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Swap Fixed Price
2015 Contracts		
Swaps	1,220,000	$(0.016)

(8) Fair Value Measurements

FASB ASC 820-10 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. Our financial instruments consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, restricted cash, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments.

Based upon quoted market prices as of September 30, 2015 and December 31, 2014, the fair value and carrying value of our senior notes was as follows (in millions):

	September 30, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$67.5	$250.0	$153.0	$250.0
8.875% senior notes due in 2020	$58.5	$223.0	$133.1	$222.8
7.875% senior notes due in 2022	$108.0	$404.1	$198.0	$404.5

Our senior notes due in 2017, 2020 and 2022 are stated 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 September 30, 2015 and December 31, 2014, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 7 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)
September 30, 2015				
Assets:				
Natural Gas Basis Derivatives	$0.1	$—	$0.1	$—
December 31, 2014				
Assets:				
Natural Gas Derivatives	2.4	—	2.4	—

Natural Gas Basis Derivatives	0.1	—	0.1	—
Liabilities:				
Natural Gas Basis Derivatives	0.1	—	0.1	—

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.

(9) Asset Retirement Obligations

We record these obligations in accordance with the guidance contained in FASB ASC 410-20. This guidance requires entities to record the fair value of a liability for legal obligations associated with the retirement obligations of tangible long-lived assets in the period in which it is incurred. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. The liability is discounted from the expected date of abandonment. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated on a unit-of-production basis as part of depreciation, depletion, and amortization expense for our oil and gas properties. Upon settlement of the liability, the Company either settles the obligation for its recorded amount or incurs a gain or loss upon settlement which is included in the “Property and Equipment” balance on our accompanying condensed consolidated balance sheets. This guidance requires us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values.

The following provides a roll-forward of our asset retirement obligation (in thousands):

	2015	
Asset Retirement Obligations recorded as of January 1	$ 72,831	
Accretion expense	4,156	
Liabilities incurred for new wells and facilities construction	147	
Reductions due to sold and abandoned wells and facilities	(4,574	)
Revisions in estimates	12	
Asset Retirement Obligations as of September 30	$ 72,572	

At September 30, 2015 and December 31, 2014, approximately $7.1 million and $10.7 million of our asset retirement obligations were classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

(10) 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.

(11) Commitments and Contingencies

In January of 2015 the Company entered into a new eleven year lease agreement for office space in Houston, Texas. The operating lease commenced on March 1, 2015 and may be terminated after seven years. As of September 30, 2015, the minimum contractual obligations are approximately $24 million in the aggregate. We will amortize the total payments under the lease agreement on a straight-line basis over the term of the lease.

During the second quarter of 2015, the Company entered into an additional gas transportation agreement covering transportation from 2016 to 2020. The agreement increased our minimum contractual obligations, over the amounts reported in

Table of Contents

our Annual Report on Form 10-K for the year ending December 31, 2014 by approximately $39 million, with no change to our obligations during 2015. Refer to Management's Discussion and Analysis of these condensed consolidated financial statements for further discussion.

We had no other material changes from amounts referenced under Note 5 in our Notes to consolidated financial statements from our Annual Report on Form 10-K for the year ending December 31, 2014.

Table of Contents

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 report on Form 10-K for the year ended December 31, 2014. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 31 of this report.

Industry Overview

The recent collapse in oil prices is among the most severe on record. The Organization of the Petroleum Exporting Countries (OPEC) 2014 decision to increase their market share, together with production increases in early 2015, has caused considerable pressure on the oil markets for the near term. According to the Energy Information Administration (EIA), West Texas Intermediate (WTI) crude oil spot prices have fallen from a monthly high of $105.79 per barrel in June of 2014 to a recent monthly low of $42.87 per barrel in August of 2015, which equates to a 59% decrease in crude oil pricing during that period. The drop in crude oil pricing is due in large part to increased world production levels and crude oil inventories. According to the International Energy Agency (IEA), third quarter 2015 world oil production increased to 96.8 million barrels of oil per day, from 94.2 million barrels in the third quarter of 2014. Third quarter 2015 world oil demand increased to 95.2 million barrels of oil per day, from 93.2 million barrels in the third quarter of 2014. In the near term, we expect currently depressed oil prices to stimulate world oil demand and global cuts in exploration and production budgets to reduce incremental oil supply, which should ultimately restore equilibrium to the world oil market. This rebalancing of the global oil markets could also occur more quickly if OPEC cuts production. We expect significant improvement in oil prices as this rebalancing occurs.

According to the EIA, Henry Hub Natural Gas monthly spot prices have fallen from a high of $6.00 per MMBtu in February of 2014 to a recent low of $1.92 per MMBtu during the week of November 2, 2015, which equates to a 68% decrease during that period. The November 2, 2015 weekly price of $1.92/MMBtu also decreased 56% when compared with the average annual Henry Hub spot price of $4.39 per MMBtu in 2014. While these recent decreases in natural gas prices create significant near term pressure on gas producers, the longer term prospects for natural gas prices, especially in the Gulf Coast Region, are expected to be more favorable.

According to the EIA, natural gas exports to Mexico set a monthly record high in July and August of this year, averaging 3.3 billion cubic feet per day (Bcf/d), and averaged 2.7 Bcf/d in the first eight months of this year, which was 38% higher than the average price for the same period last year. Demand growth is also occurring in the electric generation sector. The natural gas share of total U.S. electricity generation surpassed the coal share in July 2015 for the second time ever, with natural gas fueling 35.0% of total generation to coal's 34.9% share. Near term forecasts of warmer winter weather together with natural gas storage levels, which are 3.2% higher than the 5-year average, have resulted in significant weakness in natural gas prices. We expect natural gas prices to recover with continued growth in U.S. demand, reduced gas-directed exploration and production budgets, and a return to more normalized weather patterns.

Company Overview

We are an independent oil and natural gas company formed in 1979 engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our South 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. Natural gas production accounted for 68% of our third quarter of 2015 production and 49% of our oil and gas sales while oil constituted 20% of our third quarter of 2015 production and 44% of our oil and gas sales.

- Balance Sheet Restructuring: We are considering a range of alternatives to improve our liquidity and balance sheet. These alternatives include new debt, equity and/or equity-linked financing alternatives, exchange offers, asset sales and other avenues to protect value for the Company and its various constituents. We are currently engaged in ongoing negotiations with a group of holders of our outstanding senior notes regarding restructuring our senior notes, along with possible avenues for increasing our near-term liquidity, with no understandings reached to date. The outcome of the consideration of these potential alternatives and our ongoing bondholder negotiations, the timing of which cannot be accurately predicted at this time, are likely to affect our liquidity, future operations and financial condition.

- The significant decline in crude oil and natural gas prices has affected our business: Oil prices throughout the current year have been significantly lower than 2014 prices, with our average oil prices received falling from approximately $72 per barrel during the fourth quarter of 2014 to approximately $45 per barrel in the third quarter of 2015 (approximately a 38% decrease). Natural gas prices have also been lower during the same period, with our average natural gas prices received falling from

Table of Contents

$3.58 per Mcf during the fourth quarter of 2014 to $2.51 per Mcf in the third quarter of 2015 (approximately 30% lower). These price decreases have had a significant impact on our results and financial condition during 2015. If lower crude oil and natural gas prices persist or worsen, our future cash flows and financial condition will be negatively impacted.

- 2015 planned capital expenditures: Recent lower oil and natural gas prices have reduced operating cash flows and, as a result, we have meaningfully reduced our capital spending in 2015 compared to 2014 levels. The Company is targeting annual production levels of 11.6 to 11.7 MMBoe based on planned full-year capital expenditures of $110 to $120 million, with a primary focus on drilling activity in our dry gas Fasken area in Webb County and our South AWP area in McMullen County. A portion of our capital expenditure program is discretionary and may be further deferred, if necessary. Our full year 2015 capital budget calls for fourth quarter capital expenditures of approximately $20 to $30 million, which we currently intend to fund out of the remaining $23 million of availability under our recently amended credit facility, along with operating cash flow.

- 2015 cost reduction initiatives: We have taken significant actions to reduce our future capital, operating and overhead costs. During the first nine months of 2015 we have reduced drilling and completion costs and terminated one of our drilling contracts. In conjunction with the reduction in our capital spending plans for 2015, we continue to negotiate with all of our primary suppliers and service companies to reduce our capital and operating cost structures. These initiatives have already helped us recognize a meaningful reduction of costs during the first nine months of 2015, with our lease operating expenses, excluding workover costs, decreasing from $66.3 million spent during the nine months of 2014 to $52.7 million spent during the first nine months of 2015. By focusing operations in our high quality Fasken and AWP areas, we will continue to reduce our development costs by taking advantage of existing infrastructure and experienced operating personnel. During 2015, the Company also implemented various cost savings efforts including a significant headcount reduction and the signing of a new lease agreement for reduced corporate office space. As a result of these changes, our net general and administrative costs have decreased from $33.6 million during the first nine months of 2014 to $31.5 million during the first nine months of 2015, including non-recurring costs incurred during 2015 of approximately $2.8 million related to the initial implementation of these cost savings efforts. These changes will allow us to continue recognizing a meaningful reduction in costs through the end of the year and provide prospective sustained lower overhead costs.

- NYSE Notice of non-compliance with continued listing standards. Our common stock continues to trade on the NYSE. Since the Company’s August 14, 2015 receipt of notice of listing non-compliance from the NYSE due to the 30-day average closing price of our common stock being below $1.00 per share and our 30-day average global capitalization being below $50 million, we have submitted to the NYSE an 18-month business plan to regain compliance with the global capitalization standard and we have had our plan accepted by the NYSE. Even though the NYSE has accepted our 18-month business plan on the global capitalization standard, we remain subject to the 6-month cure period for the price per share standard that ends February 14, 2016 but could be extended through the date of our annual shareholders’ meeting in May 2016. The continued listing of our common stock for trading on the NYSE will depend on our ability, within the cure periods previously noted, to remedy these compliance deficiencies.

Third Quarter 2015 Operating Highlights

- Increasing capacity and enhancing asset value in the Eagle Ford: During the third quarter of 2015 the Company secured an additional 30 MMcf per day of firm capacity out of the Fasken area. The Company now has total firm capacity of 190 MMcf per day to support continued development of the Eagle Ford in its Webb County acreage. During the third quarter of 2015, the Company also drilled and completed its first upper Eagle Ford well in Fasken.

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. We are using proprietary 3D seismic techniques to identify a narrow high quality interval of the lower Eagle Ford within which to steer our laterals, resulting in marked improvement in our well results. Before completion operations commence, we conduct GEOFRAC logging of the horizontal well bore, which has led to more effective placement of frac stages and has also assisted in identifying sections of rock that are ideal for stimulation. These techniques have been effectively deployed in wells drilled in our Fasken and North AWP areas as well as the joint venture area in the central portion of AWP, proving the transferability of this technology. We have observed that longer laterals with additional frac stages and more intense treatment of each stage have resulted in improved rates of return of our Eagle Ford horizontal wells when comparing results using normalized oil and gas prices. Our current process allows us to drill wells in our Fasken area with laterals of over 7,500 feet and over 20 frac stages per well. We believe the successful extension of lateral lengths, increased number of frac stages and engineered spacing of these stages will result in further improvements in our economic returns across all of our Eagle Ford acreage.

Table of Contents

- Improved value of Eagle Ford shale assets through reductions 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 2015 average per well drilling costs decreasing, with the average per well cost for our Fasken wells decreasing to $2.2 million during third quarter of 2015 from $3.1 million during 2014. We have also experienced efficiency gains in our hydraulic fracturing activities (including the testing of a new enhanced completion design during the third quarter of 2015), lowering the overall frac cost per stage while performing more frac stages per well, using additional proppant in each stimulated stage and achieving better overall results as measured by rates of return and net present value. As a result of these improvements, the average completion cost per well in the Fasken area has decreased to $3.4 million during the third quarter of 2015 from $4.6 million during 2014. The combined drilling and completion costs per well for the third quarter of 2015 have been reduced to $5.6 million, on average, from $7.7 million during 2014.

- Third quarter 2015 revenues and net loss: Our third quarter oil and gas revenues decreased 55%, or $73.9 million, when compared to third quarter of 2014 revenues, primarily due to overall lower commodity pricing as well as 33% lower oil and 29% lower NGL production, partially offset by 18% higher natural gas production. Our net loss of $354.6 million for the third quarter of 2015 is primarily due to the $321.5 million non-cash write-down of our oil and gas properties.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows from operations, borrowings under our credit facility and issuances of senior notes. Our primary use of cash flow has been to fund capital expenditures used to develop our oil and gas properties. We summarize below net cash provided by operating activities for the first nine months of 2015, the amended terms of our credit agreement and available borrowings under it, 2015 capital expenditures and our related consideration of opportunities to improve our liquidity and balance sheet.

- 2015 borrowing base redeterminations and credit facility financial covenants: As part of our regularly scheduled November 2015 borrowing base redetermination, our revolving credit facility borrowing base and commitment amounts were reduced to $330.0 million from $375.0 million, resulting in $23 million of remaining availability under the credit facility as of November 2, 2015 (refer to Note 5 of these condensed consolidated financial statements for more information). Our interest payment obligations under our senior notes over the next 75 days (between November 2, 2015 and January 15, 2016) total approximately $19 million.

Additionally, the revolving credit facility has been amended to provide for revised financial covenants (refer to Note 5 of these condensed consolidated financial statements for more information), including removal of the existing liquidity requirement and the following changes:

- The adjusted working capital ratio is being reduced for the remainder of 2015 and all of 2016 to 0.5 to 1.0, and will then return to its previous minimum ratio of 1.0 to 1.0 thereafter

- The ratio of EBITDAX to Interest Expense (the interest coverage ratio) is being reduced for the remainder of 2015 and through June 30, 2016 to 1.15 to 1.0, increasing for the remainder of 2016 to 1.3 to 1.0, then increasing to 2.0 to 1.0 thereafter.

- The senior secured leverage ratio is being increased for the remainder of 2015 and through June 30, 2016 to 3.5 to 1.0, decreasing for the remainder of 2016 to 3.0 to 1.0, then decreasing to 2.5 to 1.0 thereafter.

Additionally, as part of the credit agreement amendment, an interim borrowing base redetermination on or about February 1, 2016 will be required if we have not reduced the current outstanding principal amount of our unsecured or subordinated debt by at least 50% by that date. The amended facility also increased the interest rate to be paid under the credit facility by 25 basis points on a going-forward basis, and increased the required collateral coverage from 75% to 95%.

As of September 30, 2015, we were in compliance with all of the financial covenant ratios (including being in compliance with the liquidity covenant as of our most recent interest payment in September of 2015). Based upon our current estimates of production and current commodity futures prices, our ability to remain in compliance with these financial covenant ratios in future periods is uncertain and will be impacted by a number of factors, including those which are not within our control. If we are unable to comply with these covenants or those in our senior notes (all of which were trading at approximately 27% of face value on a fair value basis as of September 30, 2015, refer to Note 8 of these condensed consolidated financial

Table of Contents

statements), we may be required to request waivers, otherwise amend our debt instruments to address our noncompliance or possibly repay some or all amounts outstanding thereunder.

If we experience the continuation of low oil and gas prices, or if they decline even further, we anticipate that our existing revolving credit facility borrowing base and commitment amounts will be reduced further (on the date of our next borrowing base redetermination) from the current $330.0 million. If that were to occur we may need to repay any borrowings above the level of any revised borrowing base and/or we may need to further amend our current financial covenants. We are focused on our balance sheet and additional financing opportunities and options to reduce our reliance on our revolving credit facility and improve Swift Energy's long-term liquidity, including additional capital alternatives in the marketplace.

- Outstanding bank borrowings and liquidity for the remainder of 2015: As noted above, effective November 2, 2015, we executed an amendment to our credit facility, lowering our borrowing base and commitment amount from $375.0 million to $330.0 million. As of November 2, 2015, we had approximately $302 million in outstanding borrowings under our credit facility, leaving us with availability to borrow approximately $23 million (excluding $5.1 million in letters of credit). We plan to control our liquidity during the remainder of 2015 by maintaining a reduced level of capital expenditures to match market expectations of reduced commodity prices.

- 2015 capital expenditures: Our capital expenditures on a cash flow basis were $126.8 million in the first nine months of 2015, compared to $317.0 million in the first nine months of 2014. The expenditures during the current period, which were $90.5 million on an accrual basis, were primarily devoted to developmental drilling and completion activity in our South Texas core region as we drilled two wells in our AWP Eagle Ford field and 14 wells in our Fasken field. These expenditures were funded by approximately $105 million of net borrowings under our credit facility along with operating cash flows.

- Net cash provided by operating activities: For the first nine months of 2015, our net cash provided by operating activities was $28.4 million, representing a $223.8 million decrease, compared to $252.2 million generated during the same period of 2014, primarily due to lower commodity prices and to a lesser degree due to decreased oil production which was partially offset by lower operating costs. For the three months ended September 30, 2015, our net cash used in operating activities was $1.0 million, representing a $31.2 million decrease, compared to $30.2 million in net cash provided by operating activities generated during the three months ended June 30, 2015, primarily due to higher semi-annual interest payments on our senior notes during the third quarter of 2015 and impacted to a lesser degree by other working capital changes and lower commodity prices.

- Balance Sheet Restructuring: We are considering a range of alternatives to improve our liquidity and balance sheet. These alternatives include new debt, equity and/or equity-linked financing alternatives, exchange offers, asset sales and other avenues to protect value for the Company and its various constituents. We are currently engaged in ongoing negotiations with a group of holders of our outstanding senior notes regarding restructuring our senior notes, along with possible avenues for increasing our near-term liquidity, with no understandings reached to date. The outcome of the consideration of these potential alternatives and our ongoing bondholder negotiations, the timing of which cannot be accurately predicted at this time, are likely to affect our liquidity, future operations and financial condition. We have retained Lazard Freres & Co. LLC to advise the Company's management and Board of Directors with respect to realigning our balance sheet, in addition to addressing financing alternatives and enhancing our liquidity profile. We have also hired the law firm of Jones Day to serve as our restructuring counsel.

Contractual Commitments and Obligations

In January of 2015, the Company entered into a new eleven year lease agreement for office space in Houston, Texas. The operating lease commenced on March 1, 2015 and may be terminated after seven years. During the second quarter of 2015, we signed a five-year agreement for increased gas transportation firm capacity (increased to a total of 190 MMcf per day) in the Fasken area. Refer to Note 11 of these condensed consolidated financial statements for further discussion.

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, 2014.

Table of Contents

Results of Operations

Revenues — Three Months Ended September 30, 2015 and 2014

Our oil and gas sales in the third quarter of 2015 decreased by 55% compared to oil and gas sales in the third quarter of 2014, primarily due to overall lower commodity pricing and to a lesser degree due to lower oil and NGL production, which was partially offset by higher natural gas production. Average oil prices we received were 53% lower than those received during the third quarter of 2014, while natural gas prices were 29% lower and NGL prices were 61% lower.

Crude oil production was 20% and 29% of our production volumes in the third quarters of 2015 and 2014, respectively. Crude oil sales were 44% and 62% of oil and gas sales in the third quarters of 2015 and 2014, respectively. Natural gas production was 68% and 55% of our production volumes in the third quarters of 2015 and 2014, respectively. Natural gas sales were 49% and 26% of oil and gas sales in the third quarters of 2015 and 2014, respectively. The remaining production and sales in each period came 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 September 30, 2015 and 2014:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2015	2014	2015	2014
Artesia Wells	$4.4	$13.8	267	423
AWP	20.2	58.8	905	1,208
Fasken	19.6	18.4	1,240	775
Other South Texas	0.9	2.0	53	62
Total South Texas	45.1	93.0	2,465	2,468
Southeast Louisiana	10.6	30.5	252	351
Central Louisiana	4.1	10.0	138	166
Other	0.2	0.4	10	9
Total	$60.0	$133.9	2,865	2,994

Our production decrease from 2014 to 2015 was primarily due to a decrease in natural gas production from our Artesia field and decreased oil production in the AWP and Lake Washington fields, partially offset by increased gross natural gas production in our Fasken field.

In the third quarter of 2015, our $73.9 million, or 55% decrease in oil, NGL, and natural gas sales from the prior year period resulted from:

- Price variances that had an approximate $48.1 million unfavorable impact on sales due to overall lower commodity pricing; and
- Volume variances that had a $25.8 million unfavorable impact on sales due to lower oil and NGL production, partially offset by higher natural gas production.

Table of Contents

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 September 30, 2015 and 2014:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended September 30, 2015	581	344	11.6	2,865	$45.24	$12.94	$2.51
Three Months Ended September 30, 2014	870	482	9.9	2,994	$96.12	$33.39	$3.55

For the three months ended September 30, 2015 and 2014, we recorded total net gains of less than $0.1 million and $5.0 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 $45.24 and $97.81 for the third quarters of 2015 and 2014, respectively, and our average natural gas price would have been $2.52 and $3.91 for the third quarters of 2015 and 2014, respectively.

Costs and Expenses — Three Months Ended September 30, 2015 and 2014

Our expenses in the third quarter of 2015 increased $281.4 million, compared to those in the third quarter of 2014, for the reasons noted below. Excluding the 2015 ceiling test write-down, our expenses in the third quarter of 2015 decreased $40.1 million, or 30%, when compared to expenses in the third quarter of 2014.

Lease operating cost. These expenses decreased $4.1 million, or 18%, compared to the level of such expenses in the third quarter of 2014. The decrease was due to lower supervision fees charged to LOE in addition to lower maintenance, compression, transportation and other costs as a result of concentrated efforts to reduce operating costs. Our lease operating costs per Boe produced were $6.28 and $7.37 for the three months ended September 30, 2015 and 2014, respectively.

Transportation and gas processing. These expenses increased $0.3 million, or 7% compared to the level of such expenses in the third quarter of 2014, as our production volumes decreased 4%. Our transportation and gas processing costs per Boe produced were $1.90 and $1.71 for the third quarters of 2015 and 2014, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses decreased $29.7 million, or 45% from those in the third quarter of 2014. The decrease was primarily due to a lower depletable base including decreased future development costs, partially offset by lower reserves volumes. We also reduced the number of our proved undeveloped locations due to lower commodity prices and other economic factors. Our DD&A rate per Boe of production was $12.43 and $21.82 in the third quarters of 2015 and 2014, respectively.

General and Administrative Expenses, Net. These expenses decreased $2.3 million, or 21%, from the level of such expenses in the third quarter of 2014. The decrease was primarily due to lower salaries and related benefits along with lower stock compensation, temporary labor costs and accounting fees, partially offset by higher legal and professional fees and decreased capitalized costs. Our net general and administrative expenses per Boe produced decreased to $3.03 per Boe in the third quarter of 2015 from $3.67 per Boe in the third quarter of 2014.

Severance and Other Taxes. These expenses decreased $5.6 million, or 55%, from third quarter of 2014 levels while oil and gas revenues decreased 55% and equivalent production volumes decreased 4%. The decrease was primarily driven by lower revenues and changes in the production mix to higher natural gas production in South Texas which carries a lower severance tax compared to oil production in South Texas and Louisiana. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.7% and 7.6% in the third quarters of 2015 and 2014, respectively.

Interest. Our gross interest cost in the third quarters of 2015 and 2014 was $20.7 million and $19.4 million, respectively, of which $1.2 million was capitalized, respectively.

Write-down of oil and gas properties. Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, we recorded a non-cash write-down on a before-tax basis of $321.5 million in the third quarter of 2015.

Table of Contents

Income Taxes. Our effective income tax rate was 54.8% for the third quarter of 2014. There was no benefit for income taxes in the third quarter of 2015 as the benefit for income taxes was offset by valuation allowances.

Revenues — Nine Months Ended September 30, 2015 and 2014

Our oil and gas sales in the first nine months of 2015 decreased by 56% compared to oil and gas sales in the first nine months of 2014, primarily due to overall lower commodity pricing and to a lesser degree due to lower oil and NGL production, which was partially offset by higher natural gas production. Average oil prices we received were 51% lower than those received during the first nine months of 2014, while natural gas prices were 38% lower and NGL prices were 57% lower.

Crude oil production was 22% and 29% of our production volumes in the nine months ended September 30, 2015 and 2014, respectively. Crude oil sales were 47% and 60% of oil and gas sales in the nine months ended September 30, 2015 and 2014, respectively. Natural gas production was 66% and 56% of our production volumes in the nine months ended September 30, 2015 and 2014, respectively. Natural gas sales were 44% and 29% of oil and gas sales in the nine months ended September 30, 2015 and 2014, respectively. The remaining production and sales in each period came from NGLs.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the nine months ended September 30, 2015 and 2014:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2015	2014	2015	2014
Artesia Wells	$ 15.4	$ 52.5	864	1,433
AWP	72.6	179.0	3,125	3,409
Fasken	53.1	67.6	3,361	2,698
Other South Texas	2.7	6.7	156	193
Total South Texas	143.8	305.8	7,506	7,733
Southeast Louisiana	36.8	101.9	823	1,119
Central Louisiana	14.2	32.4	445	509
Other	0.9	1.3	30	26
Total	$ 195.7	$ 441.4	8,804	9,387

Our production decrease from 2014 to 2015 was primarily due to a decrease in natural gas production for our Artesia field and a decrease in oil production in our AWP and Lake Washington fields. These decreases were partially offset by an increase in natural gas production from our Fasken and AWP fields.

During the first nine months of 2015, our $245.8 million, or 56% decrease in oil, NGL, and natural gas sales from the prior year period resulted from:

- Price variances that had an approximate $169.2 million unfavorable impact on sales due to overall lower commodity pricing; and
-

Volume variances that had a $76.5 million unfavorable impact on sales, primarily attributable to lower oil production, partially offset by higher natural gas production.

Table of Contents

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the nine months ended September 30, 2015 and 2014:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Nine Months Ended September 30, 2015	1,895	1,137	34.6	8,804	$48.97	$14.84	$2.48
Nine Months Ended September 30, 2014	2,691	1,395	31.8	9,387	$99.08	$34.55	$3.98

For the nine months ended September 30, 2015 and 2014, we recorded total net gains (losses) of $0.3 million and ($2.7 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 $48.97 and $98.80 for the nine months ended September 30, 2015 and 2014, respectively, and our average natural gas price would have been $2.49 and $3.92 for the nine months ended September 30, 2015 and 2014, respectively.

Costs and Expenses — Nine Months Ended September 30, 2015 and 2014

Our expenses in the first nine months of 2015 increased $989.3 million, compared to those in the first nine months of 2014, for the reasons noted below. Excluding the 2015 ceiling test write-down, our expenses in the first nine months of 2015 decreased $95.3 million, or 23%, when compared to expenses in the first nine months of 2014.

Lease operating cost. These expenses decreased $16.4 million, or 23%, compared to the level of such expenses in the first nine months of 2014. The decrease was due to concentrated efforts to reduce operating costs and included a decrease in supervision fees (i.e. overhead rates) charged to LOE and lower workover, labor, compression, maintenance and salt water disposal costs. Our lease operating costs per Boe produced were $6.15 and $7.52 for the nine months ended September 30, 2015 and 2014, respectively.

Transportation and gas processing. These expenses decreased $0.6 million, or 3%, compared to the level of such expenses in the first nine months of 2014, as our production volumes decreased 6%. Our transportation and gas processing costs per Boe produced were $1.80 and $1.75 for the nine months ended September 30, 2015 and 2014, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses decreased $62.7 million, or 31% from those in the first nine months of 2014. The decrease was primarily due to a lower depletable base including decreased future development costs, partially offset by lower reserves volumes. We also reduced the number of our proved undeveloped locations due to lower commodity prices and other economic factors. Our DD&A rate per Boe of production was $15.72 and $21.42 in the nine months ended September 30, 2015 and 2014, respectively.

General and Administrative Expenses, Net. These expenses decreased $2.0 million, or 6%, from the level of such expenses in the first nine months of 2014 primarily due to lower salary and related benefits expenses, largely offset by a decrease in capitalized costs. Our net general and administrative expenses per Boe produced remained comparable at $3.58 per Boe for the nine months ended September 30, 2015 and 2014, respectively.

Severance and Other Taxes. These expenses decreased $14.7 million, or 51%, from the first nine months of 2014. The decrease was primarily driven by lower oil and gas revenues as a result of decreased commodity prices along with declining oil production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.2% and 6.5% in the nine months ended September 30, 2015 and 2014, respectively.

Interest. Our gross interest cost in the first nine months of 2015 was $60.0 million, of which $3.6 million was capitalized. Our gross interest cost in the first nine months of 2014 was $59.0 million, of which $3.7 million was capitalized.

Write-down of oil and gas properties. Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, we recorded non-cash write-downs on a before-tax basis of approximately $502.6 million in the first quarter of 2015, $260.5 million in the second quarter of 2015 and $321.5 million in the third quarter of 2015, for a total of $1.1 billion for the first nine months of 2015.

Table of Contents

Income Taxes. Our effective income tax rate decreased to 6.7% from 49.1% for the nine months ended September 30, 2015 and 2014, respectively. The tax benefit of $80.1 million for the first nine months of 2015 was due to a reduction in our deferred tax liability resulting from the write-down of oil and gas properties, partially offset by a valuation allowance.

Table of Contents

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 on a property-by-property basis 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. The estimation process for both reserves and the impairment of unproved properties is 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").

Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, in 2015 we reported a non-cash write-down on a before-tax basis of $321.5 million and $1.1 billion on our oil and natural gas properties for the three and nine months ended September 30, 2015, respectively.

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.

If oil and natural gas prices remain low or decline from the prices used in the Ceiling Test, it is likely that additional non-cash write-downs of oil and gas properties will 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. However, due to current trends in commodity pricing it is likely that we will record additional ceiling test write-downs in future periods.

New Accounting Pronouncements. In May 2014, the FASB issued ASU 2014-09, which provides a single, comprehensive revenue recognition model for all contracts with customers across various industries. The guidance is effective for annual and interim reporting periods beginning after until December 15, 2017. We are currently reviewing the new requirements to determine the impact of this guidance on our financial statements.

In April 2015, the FASB issued ASU 2015-03, providing guidance on the presentation of debt issuance costs. The guidance requires debt issuance costs related to our long-term debt to be presented on the balance sheet as a reduction of the carrying amount of the long-term debt. This guidance is effective for fiscal years beginning after December 15, 2015 and for interim periods within those fiscal years, with early adoption permitted and retrospective application required. This guidance, which we plan to adopt beginning with the first quarter of 2016, is not expected to have a material impact on our financial statements.

In July 2015, the FASB issued ASU 2015-11, which changes the measurement principle for inventory from the lower of cost or market to "lower of cost and net realizable value." The standard simplifies the current guidance under which an entity must

Table of Contents

measure inventory at the lower of cost or market (market in this context is defined as one of three different measures, one of which is net realizable value). Net realizable value is defined as the “estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation.” The guidance is effective for fiscal years beginning after December 15, 2016, including interim periods thereafter, and must be applied prospectively after the date of adoption. We are currently reviewing the new requirement to determine the impact of this guidance on our financial statements.

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:

• future cash flows and their adequacy to fund ongoing operations;
• oil and natural gas pricing expectations;
• liquidity, including the potential need to sell certain assets, restructure our debt, raise additional capital or seek bankruptcy protection;
• business strategy;
• estimated oil and natural gas reserves or the present value thereof;
• the outcome of ongoing negotiations with holders of our senior notes;
• our borrowing capacity, future covenant compliance, 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;
• the amount, nature and timing of capital expenditures, including future development costs;
• timing, cost and amount of future production of oil and natural gas;
• availability of drilling and production equipment or availability of oil field labor;
• availability, cost and terms of capital;
• drilling of wells;
• availability and cost for 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-

Table of Contents

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, 2014. 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.

Table of Contents

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 in recent periods.

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 7 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 guarantees 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 September 30, 2015, we had $302.0 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.

Table of Contents

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 nine months of 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

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.

During the third quarter of 2015, there have been no material changes in our risk factors disclosed in the 2014 Annual Report Form 10-K and the Quarterly Report Form 10-Q for the quarter ended June 30, 2015, except for the following:

The prevailing commodity price environment may require us to sell certain assets, restructure our debt, raise additional capital, sell certain assets or seek bankruptcy protection.

If low commodity prices continue, we would need some form of debt restructuring, capital raising effort or asset sale in order to fund our operations and meet our substantial debt service obligations of approximately $80.0 million per year. Our management is actively pursuing improving our working capital position and/or reducing our future debt service obligations in order to remain a going concern for the foreseeable future. If we are unable to restructure our outstanding debt, obtain additional debt or equity financing, or raise adequate proceeds from sales of assets, we may not be able to make payments on our indebtedness, our secured lenders could foreclose against the assets securing their borrowings, and we may find it necessary to file a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure.

Our short-term liquidity is constrained, and could severely impact our cash flow and our development of our properties.

Currently, our principal sources of liquidity are cash flow from our operations and borrowing under our revolving credit facility. During the first nine months of 2015, we have borrowed $105 million under our revolving credit facility to fund a portion of our capital expenditures. As part of our regularly scheduled November 2015 borrowing base redetermination, our revolving credit facility borrowing base and commitments amounts were reduced to $330.0 million from $375.0 million, with approximately $23 million of remaining availability under our credit facility at November 2, 2015. If we are unable to materially reduce our obligations on our outstanding senior notes, the lenders may institute a one-time interim borrowing base redetermination on February 1, 2016 that could further reduce our existing revolving credit facility borrowing base. This reduction could result in our liquidity being severely limited and our expenditures being limited to our current cash flow. If we are no longer able to draw under our credit facility, we may not be able to fund our operations and drilling activities and pay the interest on our debt, which could result in our defaulting under our various debt instruments and possibly seeking bankruptcy protection.

Continuing required write-downs of our estimated proved reserves may reduce our borrowing capacity and ability to meet our obligations under our various debt instruments.

During the first nine months of 2015, we were required to write-down $1.1 billion of our estimated proved reserves, and we anticipate being required to write-down additional proved reserves during the fourth quarter of 2015. In addition to the negative effect on our balance sheet and retained earnings and the reduction in our assets, the reduction in value of our properties would likely reduce our future borrowing capacity and ability to meet the financial covenants under our various debt instruments.

35

Table of Contents

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

The following table summarizes repurchases of our common stock occurring during the third quarter of 2015:

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)
July 1 – 31, 2015 (1)	699	$0.80	—	$—
August 1 – 31, 2015 (1)	205	$0.65	—	—
September 1 – 30, 2015 (1)	781	$0.48	—	—
Total	1,685	$0.63	—	$—

(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.

Effective November 2, 2015, we executed an amendment to our credit facility agreement lowering our borrowing base and commitment amount, changing our financial covenant ratios as noted below, and providing for a borrowing base redetermination on or about February 1, 2016 if we have not reduced the current outstanding principal amount of our unsecured or subordinated debt by at least 50% by that date, along with other changes detailed below. The borrowing base and commitment amount under our credit facility were decreased from $375.0 million to $330.0 million while the maturity date of November 1, 2017 remained unchanged, subject to being accelerated to March 2, 2017 if by that date the maturity dates of our existing Senior Notes are not extended to May 1, 2018 or later, or if those Senior Notes are not repurchased, redeemed or refinanced.

Effective November 2, 2015, the amendment made changes to the existing adjusted working capital ratio, interest coverage ratio and senior secured leverage ratio and removed the existing liquidity requirement in order for us to pay interest on our existing senior notes or any new debt (after giving effect to such interest payment).

The adjusted working capital ratio (not less than 1.0 to 1.0 before the amendment) was amended to require the ratio to not be less than 0.5 to 1.0 for each of the quarters up to and ending on December 31, 2016, returning to a ratio of not less than 1.0 to 1.0 at any time thereafter.

The interest coverage ratio (not less than 1.5 to 1.0 before the amendment) was amended to require the ratio to not be less than 1.15 to 1.0 for the quarters ending on December 31, 2015 through June 30, 2016, 1.3 to 1.0 for the quarters ending September 30, 2016 through December 31, 2016, and 2.0 to 1.0 any time thereafter.

The senior secured leverage ratio (not greater than 3.0 to 1.0 before the amendment) was amended to require the ratio to not be greater than 3.5 to 1.0 for the quarters ending December 31, 2015 through June 30, 2016, 3.0 to 1.0 for the quarters ending September 30, 2016 through December 31, 2016, and 2.5 to 1.0 any time thereafter.

Effective with the amendment on November 2, 2015, the terms of the credit facility require us to secure the facility with collateral equal to at least 95% of our oil and natural gas properties. The amended facility also increased the interest rate to be paid under the credit facility by 25 basis points on a going-forward basis.

The above description is qualified in its entirety by reference to Exhibit 10.1 attached to this filing, which is the full text of the November 2, 2015 amendment to our credit facility agreement.

Table of Contents

Item 6. Exhibits.

10.1*	Sixth Amendment to Second Amended and Restated Credit Agreement effective as of November 2, 2015, among Swift Energy Company, Swift Energy Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto.
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

Table of Contents

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:	November 5, 2015	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President Chief Financial Officer and Principal Accounting Officer

Table of Contents

Exhibit Index

10.1*	Sixth Amendment to Second Amended and Restated Credit Agreement effective as of November 2, 2015, among Swift Energy Company, Swift Energy Operating, LLC, JPMorgan Chase Bank, N.A., as Administrative Agent, and the lenders party thereto.
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