SWIFT ENERGY CO
Form 10-Q
November 17, 2014

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, 2014
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.)

16825 Northchase Drive, Suite 400
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)	43,859,472 Shares (Outstanding at October 31, 2014)

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Preliminary Note

Immediately prior to the filing of this report, we filed a Form 10-K/A report for the fiscal year ended December 31, 2013 and Form 10-Q/A reports for the fiscal quarters ended March 31, 2014 and June 30, 2014, restating our financial statements for these periods. These filings were made to correct errors we discovered in our ceiling test calculations for prior periods and to make certain other adjustments with respect to the periods covered by those reports. Certain details regarding those errors and adjustments are discussed in Note 1A - “Restatement of Previously Issued Condensed Consolidated Financial Statements” of this Form 10-Q.

Restatement Background

On November 10, 2014, the Audit Committee of our Board of Directors (the “Audit Committee”), after discussion with management and Ernst & Young LLP (“EY”), our independent registered public accounting firm, determined that the following financial statements previously filed with the SEC should no longer be relied upon: (1) the audited consolidated financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2013; (2) the unaudited condensed consolidated financial statements included in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2013, June 30, 2013, and September 30, 2013; and (3) the unaudited condensed consolidated financial statements included our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014.

In connection with the preparation of our financial statements for the quarter ended September 30, 2014, we determined that an error occurred in our model used for the ceiling test calculation we prepared at December 31, 2013, March 31, 2009 and December 31, 2008, to determine whether the net book value of the Company's oil and gas properties exceed the ceiling. Specifically, this error related to incorrectly including the deferred income tax effect of the Company's asset retirement obligations when computing the ceiling test limitation of its oil and natural gas properties under the full-cost method of accounting. The Company determined that the error caused a material overstatement of its full-cost ceiling test write-down of oil and gas properties in periods prior to 2014.

As a result of this error, we are restating our unaudited consolidated financial statements for the three and nine months ended September 30, 2013. The correction of the error principally resulted in an increase in our depreciation, depletion and amortization expense for the three and nine months ended September 30, 2013 of approximately $0.3 million and $1.0 million, respectively, and decreased net income for the three and nine months ended September 30, 2013 by approximately $0.2 million and $0.6 million, respectively, (net of an decrease to the income tax provision for the three and nine months ended September 30, 2013, of approximately $0.1 million and $0.4 million, respectively). Please refer to Note 1A - “Restatement of Previously Issued Consolidated Financial Statements” of this Form 10-Q for more information regarding the impact of these adjustments.

Along with restating our financial statements to correct the error discussed above, we are making adjustments for certain previously identified immaterial accounting errors related to the periods covered by this form 10-Q. When these financial statements were originally issued, we assessed the impact of these errors and concluded that they were not material to our financial statements for the three and nine months ended September 30, 2013. However, in conjunction with our need to restate our financial statements as a result of the error noted above, we have determined that it would be appropriate within this Form 10-Q to make adjustments for all such previously unrecorded adjustments. Please refer to Note 1A - “Restatement of Previously Issued Consolidated Financial Statements” of this Form 10-Q for more information regarding the impact of these adjustments.

Because these revisions are treated as corrections of errors to our prior period financial results, the revisions are considered to be a “restatement” under U.S. generally accepted accounting principles. Accordingly, the revised financial information included in this Quarterly Report on Form 10-Q has been identified as “restated”.

Internal Control Consideration

Our management has determined that there was a deficiency in our internal control over financial reporting that constitutes a material weakness, as defined by SEC regulations, at September 30, 2014. For a discussion of management's consideration of our disclosure controls and procedures and the material weakness identified, see Part I, Item 4 included in this Form 10-Q.

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2014
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	September 30, 2014 (unaudited)	December 31, 2013 (As Restated)
ASSETS		
Current Assets:		
Cash and cash equivalents	$9,041	$3,277
Accounts receivable	63,385	70,897
Deferred tax asset	9,693	10,715
Other current assets	42,063	7,600
Total Current Assets	124,182	92,489
Property and Equipment:		
Property and Equipment, including $65,767 and $71,452 of unproved property costs not being amortized, respectively	5,863,650	5,714,099
Less – Accumulated depreciation, depletion, and amortization	(3,326,908)	(3,125,282)
Property and Equipment, Net	2,536,742	2,588,817
Other Long-Term Assets	14,235	17,199
Total Assets	$2,675,159	$2,698,505
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$100,493	$82,318
Accrued capital costs	48,498	61,164
Accrued interest	12,986	21,561
Undistributed oil and gas revenues	13,089	10,990
Total Current Liabilities	175,066	176,033
Long-Term Debt	1,079,269	1,142,368
Deferred Tax Liabilities	253,689	241,205
Asset Retirement Obligation	67,155	63,225
Other Long-Term Liabilities	9,631	10,324
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, 44,296,246 and 43,915,346 shares issued, and 43,857,765 and 43,401,920 shares outstanding, respectively	443	439
Additional paid-in capital	769,663	762,242
Treasury stock held, at cost, 438,481, and 513,426 shares, respectively	(9,744)	(12,575)
Retained earnings	329,987	315,244
Total Stockholders' Equity	1,090,349	1,065,350
Total Liabilities and Stockholders' Equity	$2,675,159	$2,698,505

See accompanying Notes to Condensed Consolidated Financial Statements.

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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,	
	2014	2013 (As Restated)	2014	2013 (As Restated)
Revenues:				
Oil and gas sales	$133,896	$152,981	$441,440	$442,015
Price-risk management and other, net	4,898	(2,048)	(2,472)	(714)
Total Revenues	138,794	150,933	438,968	441,301
Costs and Expenses:				
General and administrative, net	10,981	11,146	33,565	35,062
Depreciation, depletion, and amortization	65,331	67,274	201,072	187,503
Accretion of asset retirement obligation	1,445	1,478	4,246	4,732
Lease operating cost	22,067	23,078	70,606	76,919
Transportation and gas processing	5,107	5,783	16,412	15,386
Severance and other taxes	10,191	11,695	28,829	32,221
Interest expense, net	18,197	17,495	55,295	51,297
Total Costs and Expenses	133,319	137,949	410,025	403,120
Income Before Income Taxes	5,475	12,984	28,943	38,181
Provision for Income Taxes	3,001	5,625	14,200	15,235
Net Income	$2,474	$7,359	$14,743	$22,946
Per Share Amounts-				
Basic: Net Income	$0.06	$0.17	$0.34	$0.53
Diluted: Net Income	$0.06	$0.17	$0.33	$0.53
Weighted Average Shares Outstanding - Basic	43,850	43,389	43,768	43,308
Weighted Average Shares Outstanding - Diluted	44,473	43,704	44,299	43,624

See accompanying Notes to Condensed Consolidated Financial Statements.

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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	Total
Balance, December 31, 2012 (As Restated)	$435	$748,517	$(13,855)	$317,686	$1,052,783
Stock issued for benefit plans (104,890 shares)	—	(1,171)	2,793	—	1,622
Shares issued from option exercises (1,125 shares)	—	4	—	—	4
Purchase of treasury shares (98,020 shares)	—	—	(1,513)	—	(1,513)
Tax shortfall from share-based compensation	—	(1,607)	—	—	(1,607)
Employee stock purchase plan (72,273 shares)	1	945	—	—	946
Issuance of restricted stock (391,581 shares)	3	(3)	—	—	—
Amortization of share-based compensation	—	15,557	—	—	15,557
Net Loss	—	—	—	(2,442)	(2,442)
Balance, December 31, 2013 (As Restated)	$439	$762,242	$(12,575)	$315,244	$1,065,350
Stock issued for benefit plans (154,665 shares) (1)	—	(1,876)	3,785	—	1,909
Purchase of treasury shares (79,720 shares) (1)	—	—	(954)	—	(954)
Employee stock purchase plan (71,825 shares) (1)	1	823	—	—	824
Issuance of restricted stock (309,075 shares) (1)	3	(3)	—	—	—
Amortization of share-based compensation (1)	—	8,477	—	—	8,477
Net Income (1)	—	—	—	14,743	14,743
Balance, September 30, 2014	$443	$769,663	$(9,744)	$329,987	$1,090,349

(1) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2014	2013 (As Restated)
Cash Flows from Operating Activities:		
Net income	$14,743	$22,946
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	201,072	187,503
Accretion of asset retirement obligation	4,246	4,732
Deferred income taxes	13,507	15,235
Share-based compensation expense	5,571	8,454
Other	(390)	(4,093)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable and other current assets	14,159	(3,293)
Increase (decrease) in accounts payable and accrued liabilities	7,299	2,588
Increase (decrease) in income taxes payable	543	(208)
Increase (decrease) in accrued interest	(8,575)	(8,257)
Net Cash Provided by Operating Activities	252,175	225,607
Cash Flows from Investing Activities:		
Additions to property and equipment	(316,972)	(435,722)
Proceeds from the sale of property and equipment	145,535	6,990
Funds withdrawn from restricted cash account	6,501	—
Funds deposited into restricted cash account	(18,345)	—
Net Cash Used in Investing Activities	(183,281)	(428,732)
Cash Flows from Financing Activities:		
Proceeds from bank borrowings	639,000	968,500
Payments of bank borrowings	(702,000)	(764,900)
Net proceeds from issuances of common stock	824	946
Purchase of treasury shares	(954)	(1,494)
Net Cash Provided by (Used in) Financing Activities	(63,130)	203,052
Net increase (decrease) in Cash and Cash Equivalents	5,764	(73)
Cash and Cash Equivalents at Beginning of Period	3,277	170
Cash and Cash Equivalents at End of Period	$9,041	$97
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$61,983	$57,990
Cash paid during period for income taxes	$150	$208

See accompanying Notes to Condensed Consolidated Financial Statements.

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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/A for the fiscal year ended December 31, 2013 as filed with the Securities and Exchange Commission on November 17, 2014.

(1A) Restatement of Previously Issued Condensed Consolidated Financial Statements

Overview. In connection with the preparation of our financial statements for the quarter ended September 30, 2014, we determined that the ceiling test calculation we had prepared at December 31, 2013, March 31, 2009 and December 31, 2008, to determine whether the net book value of the Company's oil and gas properties exceed the ceiling, incorrectly included the deferred income tax effect of the Company's asset retirement obligations when computing the ceiling test limitation of its oil and natural gas properties under the full-cost method of accounting. The Company determined that the error caused a material overstatement of its full-cost ceiling test write-down of oil and gas properties in periods prior to 2014, more specifically in the fourth quarter of 2013, in the first quarter of 2009 and the fourth quarter of 2008, including associated depletion for all periods presented. As a result of this error, in this Form 10-Q we are restating our unaudited condensed consolidated financial information for the three and nine months ended September 30, 2013.

For the 2013 periods presented herein, the correction of the error principally results in an increase in our depreciation, depletion and amortization expense for the three and nine months ended September 30, 2013 of approximately $0.3 million and $1.0 million, respectively, and decreased net income for the three and nine months ended September 30, 2013 by approximately $0.2 million and $0.6 million, respectively (net of a decrease to the income tax benefit for the three and nine months ended September 30, 2013, of approximately $0.1 million and $0.4 million, respectively).

Along with restating our financial statements to correct the error discussed above, we have recorded adjustments for certain previously identified immaterial accounting errors related to the periods covered by this Form 10-Q. When these financial statements were originally issued, we assessed the impact of these errors and concluded that they were not material to our financial statements for the three and nine months ended September 30, 2013. However, in conjunction with our need to restate our financial statements as a result of the error noted above, we have determined that it would be appropriate to make adjustments within this Form 10-Q for all such previously unrecorded adjustments.

The combined impacts of all adjustments to the applicable line items in our unaudited condensed consolidated financial statements for the periods covered by this Form 10-Q are provided in the tables below.

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The following tables present the effect of the correction of the error and other adjustments on selected line items of our previously reported unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2013 (in thousands):

	Condensed Consolidated Statements of Operations For the Three Months Ended September 30, 2013			Condensed Consolidated Statements of Operations For the Nine Months Ended September 30, 2013		
	(As Reported)	Adjustments	(As Restated)	(As Reported)	Adjustments	(As Restated)
Oil and Gas Sales	$155,049	$(2,068)	$152,981	$442,418	$(403)	$442,015
Total Revenues	153,001	(2,068)	150,933	441,704	(403)	441,301
Depreciation, depletion, and amortization	66,948	326	67,274	186,526	977	187,503
Lease operating cost	23,078	—	23,078	77,459	(540)	76,919
Transportation and gas processing	5,783	—	5,783	16,678	(1,292)	15,386
Severance and other taxes	11,695	—	11,695	31,971	250	32,221
Total Costs and Expenses	137,623	326	137,949	403,725	(605)	403,120
Income (Loss) from Continuing Operations Before Income Taxes	15,378	(2,394)	12,984	37,979	202	38,181
Provision (Benefit) for Income Taxes	6,492	(867)	5,625	15,162	73	15,235
Net Income (Loss)	8,886	(1,527)	7,359	22,817	129	22,946
Basic EPS: Net Income (Loss)	$0.20	$(0.03)	$0.17	$0.53	$—	$0.53
Diluted EPS: Net Income (Loss)	$0.20	$(0.03)	$0.17	$0.52	$0.01	$0.53

	Consolidated Statements of Cash Flows For the Nine Months Ended September 30, 2013		
	(As Reported)	Adjustments	(As Restated)
Net income (loss)	$22,817	$129	$22,946
Depreciation, depletion, and amortization	186,526	977	187,503
Deferred income taxes	15,162	73	15,235
Other	(3,796)	(297)	(4,093)
(Increase) decrease in accounts receivable	(3,696)	403	(3,293)
Increase (decrease) in accounts payable and accrued liabilities	3,873	(1,285)	2,588
Net Cash Provided by Operating Activities	225,607	—	225,607

(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. We have evaluated subsequent events of our consolidated financial statements. There were no 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

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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 and the related present value of estimated future net cash flows therefrom,
- 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 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, 2014 and 2013, such internal costs capitalized totaled $6.9 million and $7.9 million, respectively. For the nine months ended September 30, 2014 and 2013, such internal costs capitalized totaled $20.9 million and $23.9 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended September 30, 2014 and 2013, capitalized interest on unproved properties totaled $1.2 million and $1.8 million, respectively. For the nine months ended September 30, 2014 and 2013, capitalized interest on unproved properties totaled $3.7 million and $5.6 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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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, 2014	December 31, 2013 (As Restated)
Property and Equipment		
Proved oil and gas properties	$5,755,886	$5,600,279
Unproved oil and gas properties	65,767	71,452
Furniture, fixtures, and other equipment	41,997	42,368
Less – Accumulated depreciation, depletion, and amortization	(3,326,908)	(3,125,282)
Property and Equipment, Net	$2,536,742	$2,588,817

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 property-by-property 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 during the period by the total estimated units of proved oil and natural gas reserves 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.

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”). This calculation is done on a country-by-country basis.

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.

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It is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the future and that non-cash write-downs of oil and natural gas properties could occur in the future. For example, 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, non-cash write-downs of our oil and natural gas properties could occur. We cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties.

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, 2014 and December 31, 2013, 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, 2014 and December 31, 2013, we had an allowance for doubtful accounts of approximately $0.4 million and $0.1 million, respectively. The allowance for doubtful accounts has been deducted from the total “Accounts receivable” balance on the accompanying condensed consolidated balance sheets.

At September 30, 2014, our “Accounts receivable” balance included $51.9 million for oil and gas sales, $1.9 million for joint interest owners, $7.9 million for severance tax credit receivables and $1.7 million for other receivables. At December 31, 2013, our “Accounts receivable” balance included $56.9 million for oil and gas sales, $1.6 million for joint interest owners, $11.6 million for severance tax credit receivables and $0.8 million for other receivables.

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 were capitalized and are 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, 2014, was $1.4 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at September 30, 2014, was $3.2 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at September 30, 2014, was $6.1 million. The balance of revolving credit facility issuance costs at September 30, 2014, was $2.5 million.

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, 2014 and 2013, we recorded a net gain of $5.0 million and a net loss of $2.0 million, respectively, relating to our derivative activities. The 2014 amount includes a revenue increase of $1.2

million during the third quarter of 2014 for the non-cash fair value adjustments on commodity derivatives. For the nine months ended September 30, 2014 and 2013, we recorded net losses of $2.7 million and $0.8 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, 2014 was $0.7 million which was recognized on the accompanying condensed consolidated balance sheet in “Other current assets.” The fair values of our current and non-current unsettled derivative liabilities at September 30, 2014 were $0.5 million and $0.1 million which were recognized on the accompanying condensed consolidated balance sheet in “Accounts payable and accrued liabilities” and “Other Long-Term Liabilities”, respectively.

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At September 30, 2014, we had $1.0 million in receivables for settled derivatives which were recognized on the accompanying condensed consolidated balance sheet in “Accounts receivable” and were subsequently collected in October 2014. At September 30, 2014, we also had $0.1 million in payables for settled derivatives which were recognized on the accompanying condensed consolidated balance sheet in "Accounts payable and accrued liabilities" and were subsequently paid in October 2014.

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 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 and liability of $0.1 million at September 30, 2014 and December 31, 2013, respectively. For further discussion related to the fair value of the Company's derivatives, refer to Note 7 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, 2014:

Natural Gas Derivatives (NYMEX Henry Hub Settlements)	Total Volumes (MMBtu)	Swap Fixed Price	Collars Floor Price	Ceiling Price
2014 Contracts				
Swaps	3,330,000	$ 4.32		
Collars	1,035,000		$ 4.15	$ 4.55
2015 Contracts				
Swaps	900,000	$ 4.42		

Natural Gas Basis Derivatives (East Texas Houston Ship Channel Settlements)	Total Volumes (MMBtu)	Swap Fixed Price
2014 Contracts		
Swaps	4,200,000	$ (0.11)
2015 Contracts		
Swaps	8,200,000	$ (0.02)

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 based on COPAS industry guidelines. The amount of supervision fees charged for the three and nine months ended September 30, 2014 and 2013 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated were $3.5 million and $2.8 million for the three months ended September 30, 2014 and 2013, respectively and $9.2 million and $8.9 million for the nine months ended September 30, 2014 and 2013, respectively.

Inventories. Inventories consist primarily of tubulars and other equipment and supplies that we expect to place in service in production operations. Inventories carried at cost (weighted average method) are included in “Other current assets” on the accompanying condensed consolidated balance sheets totaling $3.1 million and $3.5 million at September 30, 2014 and December 31, 2013, respectively.

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

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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, 2014, 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 2008 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 nine months ended September 30, 2014, we recognized an income tax expense increase of $2.1 million related to a shortfall between the tax deduction received with respect to prior restricted stock grants that vested during the year versus the actual book expense recorded over the life of those grants.

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, 2014	December 31, 2013 (As Restated)
Trade accounts payable (1)	$ 25,624	$ 30,769
Accrued operating expenses	14,451	16,016
Accrued payroll costs	11,212	10,938
Asset retirement obligation – current portion	13,292	15,859
Accrued taxes	9,626	5,845
Deposit liability (2)	22,685	—
Other payables	3,603	2,891
Total accounts payable and accrued liabilities	$ 100,493	$ 82,318

(1) Included in “trade accounts payable” are liabilities of approximately $9.6 million and $26.1 million at September 30, 2014 and December 31, 2013, respectively, for outstanding checks.
(2) This amount equals the liability related to funds received from Saka Energi that are maintained in a restricted cash account. Refer to the "Short-Term Restricted Cash" discussion below for further information.

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.

Short-Term Restricted Cash (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 are 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. All cash deposited in the account is contractually restricted for use in the Fasken development program and therefore is recorded as restricted cash until the Company has performed the related development activities.

As of September 30, 2014, we recorded $34.5 million of restricted cash including $11.8 million for deposits from Swift Energy with the remaining deposits from Saka Energi. The restricted cash balance is reported in “Other current assets” while the related deposit liability is reported in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

During the quarter Saka Energi deposited $29.8 million into the account while $7.1 million was withdrawn from the account in order to fund on-going development operations in the Fasken area. The cash changes from the account relating to Saka Energi's contributions are shown in the operating activities section of the accompanying condensed consolidated statements of cash flows. The cash changes from the account relating to Swift Energy's contributions are 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, 2014 and December 31, 2013, these assets were approximately $1.0 million.

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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.

Asset Retirement Obligation. 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):

	2014
Asset Retirement Obligation recorded as of January 1	$ 79,084
Accretion expense	4,246
Liabilities incurred for new wells and facilities construction	470
Reductions due to sold and abandoned wells and facilities	(2,914)
Revisions in estimates	(439)
Asset Retirement Obligation as of September 30	$ 80,447

At September 30, 2014 and December 31, 2013, approximately $13.3 million and $15.9 million of our asset retirement obligation was classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

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 is effective for annual and interim reporting periods beginning after December 15, 2016 and upon adoption, entities are required 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. We plan to review and assess the effect and implement any necessary requirements as needed.

(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, 2014, as well as Note 6 of our consolidated financial statements in our Annual Report on Form 10-K/A for the fiscal year ended December 31, 2013, 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. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the three and nine months ended September 30, 2014, we recognized an income tax shortfall in earnings of $0.2 million and $2.1 million, respectively, primarily related to restricted stock awards that vested at a price lower than the grant date fair value. For the three and nine months ended September 30, 2013, we did not recognize any material excess tax benefit or shortfall in earnings. There were no stock option exercises for the nine months ended September 30, 2014 and 2013.

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 $1.7 million and

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$2.2 million for the three months ended September 30, 2014 and 2013, respectively and $5.1 million and $7.8 million for the nine months ended September 30, 2014 and 2013, respectively. Share-based compensation recorded in lease operating cost was $0.1 million for the three months ended September 30, 2014 and 2013 and was $0.2 million for the nine months ended September 30, 2014 and 2013, respectively. We also capitalized $0.9 million and $1.2 million of share-based compensation for the three months ended September 30, 2014 and 2013, respectively, and capitalized $2.9 million and $4.4 million for the nine months ended September 30, 2014 and 2013, 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 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, 2014 and 2013 we did not grant any stock option awards.

At September 30, 2014, we had $0.2 million of unrecognized compensation cost related to stock option awards, which is expected to be recognized over a weighted-average period of 0.4 years. The following table represents stock option award activity for the nine months ended September 30, 2014:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,488,314	$33.38
Options granted	—	$—
Options canceled	(90,527)	$25.20
Options exercised	—	$—
Options outstanding, end of period	1,397,787	$33.88
Options exercisable, end of period	1,295,616	$33.98

Our stock option awards outstanding and exercisable at September 30, 2014 were out of the money and therefore had no aggregate intrinsic value. At September 30, 2014, the weighted average contract life of stock option awards outstanding was 4.8 years and the weighted average contract life of stock option awards exercisable was 4.6 years. There were no stock option exercises for the nine months ended September 30, 2014 and 2013.

Restricted Stock Awards

The plans, as described in Note 6 of our consolidated financial statements in our Annual Report on Form 10-K/A for the fiscal year ended December 31, 2013, 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, 2014, we had unrecognized compensation expense of $12.4 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.7 years. The grant date fair value of shares vested during the nine months ended September 30, 2014 was $10.6 million.

The following table represents restricted stock award activity for the nine months ended September 30, 2014:

	Shares	Wtd. Avg. Grant Price

Restricted shares outstanding, beginning of period	1,267,110	$ 21.54
Restricted shares granted	743,150	$ 11.58
Restricted shares canceled	(139,973)	$ 15.16
Restricted shares vested	(308,825)	$ 34.27
Restricted shares outstanding, end of period	1,561,462	$ 14.85

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Performance-Based Restricted Stock Units

For the nine months ended September 30, 2014 and 2013, the Company granted 185,250 and 189,700 units, respectively, of performance-based restricted stock units containing predetermined market and performance conditions with a cliff vesting period of 3.1 years. These units were granted at 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target.

The compensation expense for the market condition is based on the per unit grant date valuation using a Monte-Carlo simulation. The performance condition is remeasured quarterly and compensation expense is recorded based on the closing market price of our stock per unit on the grant date multiplied by the expected payout level. The payout level is calculated based on actual performance achieved during the performance period compared to a defined peer group.

As of September 30, 2014, we had unrecognized compensation expense of $2.8 million related to our restricted stock units which is expected to be recognized over a weighted-average period of 2.0 years. No shares vested during the nine months ended September 30, 2014 and 2013. The weighted average grant date fair value for the restricted stock units granted during the nine months ended September 30, 2014 and 2013 was $11.68 and $15.01 per unit, respectively.

The following table represents restricted stock unit activity for the nine months ended September 30, 2014:

	Shares	Wtd. Avg. Grant Price
Restricted stock units outstanding, beginning of period	189,700	$ 15.01
Restricted stock units granted	185,250	$ 11.68
Restricted stock units canceled	—	$ —
Restricted stock units vested	—	$ —
Restricted stock units outstanding, end of period	374,950	$ 13.36

(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. 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 2013, 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, 2014 and 2013 (in thousands, except per share amounts):

	Three Months Ended September 30, 2014			Three Months Ended September 30, 2013 (As Restated)		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 2,474	43,850	$ 0.06	$ 7,359	43,389	$ 0.17
Dilutive Securities:						

Restricted Stock Awards		564			288	
Restricted Stock Units		59			27	
Diluted EPS:						
Net Income and Assumed Share Conversions	$2,474	44,473	$0.06	$7,359	43,704	$0.17

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	Nine Months Ended September 30, 2014			Nine Months Ended September 30, 2013 (As Restated)		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$14,743	43,768	$0.34	$22,946	43,308	$0.53
Dilutive Securities:						
Restricted Stock Awards		469			249	
Restricted Stock Units		62			67	
Diluted EPS:						
Net Income and Assumed Share Conversions	$14,743	44,299	$0.33	$22,946	43,624	$0.53

Approximately 1.4 million and 1.6 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended September 30, 2014 and 2013, respectively, and approximately 1.4 million and 1.6 million stock options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2014 and 2013 because these stock options were antidilutive. Approximately 0.2 million restricted stock awards were not included in the computation of Diluted EPS for the three months ended September 30, 2014 and 2013, and approximately 0.3 million restricted stock awards were not included in the computation of Diluted EPS for the nine months ended September 30, 2014 and 2013 because they were antidilutive. Approximately 0.7 million and 0.4 million shares for three and nine months ended September 30, 2014 and 2013, 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.

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(5) Long-Term Debt

Our long-term debt as of September 30, 2014 and December 31, 2013, was as follows (in thousands):

	September 30, 2014	December 31, 2013
7.125% senior notes due in 2017	$ 250,000	$ 250,000
8.875% senior notes due in 2020 (1)	222,691	222,446
7.875% senior notes due in 2022 (1)	404,578	404,922
Bank Borrowings due in 2017	202,000	265,000
Long-Term Debt (1)	$ 1,079,269	$ 1,142,368

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

As of September 30, 2014, we had $202.0 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 have capitalized interest on our unproved properties in the amount of $1.2 million and $1.8 million for the three months ended September 30, 2014 and 2013, respectively, and we have capitalized interest on our unproved properties in the amount of $3.7 million and $5.6 million for the nine months ended September 30, 2014 and 2013, respectively.

Bank Borrowings. Effective October 17, 2014, our syndicate of 11 banks reaffirmed the borrowing base and commitment amount of $417.6 million on our $500.0 million credit facility. The maturity date of November 1, 2017 remained unchanged.

We had $202.0 million and $265.0 million in outstanding borrowings under our credit facility at September 30, 2014 and December 31, 2013, respectively. The interest rate on our credit facility is 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 is 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 will then apply. The applicable margins vary depending on the level of outstanding debt with escalating rates of 50 to 150 basis points above the Alternative Base Rate and escalating rates of 150 to 250 basis points for Eurodollar rate loans. At September 30, 2014, the lead bank's prime rate was 3.25%. The commitment fee associated with the credit facility fluctuated between 0.38% and 0.50% for the three months ended September 30, 2014.

The terms of our credit facility include, 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, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX as defined in the terms of our credit facility) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. As of September 30, 2014, we were in compliance with the provisions of this agreement. The credit facility is secured by 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.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.7 million and $1.6 million for the three months ended September 30, 2014 and 2013, respectively. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $5.9 million and $4.0 million for the nine months ended September 30, 2014 and 2013, respectively. The amount of commitment fees included in interest expense, net was $0.2 million for the three months ended September 30, 2014 and 2013, and was $0.6 million and $0.9 million for the nine months ended September 30, 2014 and 2013.

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

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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, prior to March 1, 2015, 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, 2014.

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, 2014 and 2013 and $23.7 million for the nine months ended September 30, 2014 and 2013.

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. On or after January 15, 2015, 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, 2014.

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, 2014 and 2013 and $15.6 million and $15.5 million for the nine months ended September 30, 2014 and 2013, respectively.

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 102.375% of the principal, plus accrued and unpaid interest, declining in twelve-month intervals to 100% on June 1, 2015 and thereafter. 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, 2014.

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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, 2014 and 2013 and $13.7 million for the nine months ended September 30, 2014 and 2013.

(6) Acquisitions and Dispositions

On July 15, 2014, we closed our transaction with Saka Energi to fully develop 8,300 acres of Fasken area Eagle Ford shale properties owned by Swift Energy in Webb County, Texas, with an effective date of January 1, 2014. Swift Energy sold a 36% full participating interest in the Fasken properties to Saka Energi for $175 million in total cash consideration, with $125 million paid at closing (subject to adjustments for the interim period between the effective date and the closing date) and $50 million in cash to be paid by Saka Energi over time to carry a portion of Swift Energy's field development costs incurred after the effective date. As of September 30, 2014, approximately $35 million remained of Saka Energi's original $50 million carry obligation. At closing, the company received approximately $147 million in proceeds, including a $12.5 million deposit received during the prior quarter which was held in an escrow account until the closing date, as well as adjustments for the interim period between the effective date and the closing date. The proceeds initially were used to reduce our outstanding borrowings on our credit facility which were partially offset by additional borrowings against the credit facility during the quarter to fund development expenditures. No gain or loss was recognized for the transaction as the proceeds were applied to the full cost pool.

(7) Fair Value Measurements

FASB ASC 820-10 defines fair value, establishes guidelines for measuring fair value and expands disclosure about fair value measurements. It does not create or modify any current GAAP requirements to apply fair value accounting. However, it provides a single definition for fair value that is to be applied consistently for all prior accounting pronouncements.

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, 2014 and December 31, 2013, the fair value and carrying value of our senior notes was as follows (in millions):

	September 30, 2014		December 31, 2013	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$251.9	$250.0	$256.7	$250.0
8.875% senior notes due in 2020	$225.0	$222.7	$239.1	$222.4
7.875% senior notes due in 2022	$411.0	$404.6	$409.0	$404.9

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

The following table presents our assets and liabilities that are measured at fair value as of September 30, 2014 and December 31, 2013, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 2 of these condensed consolidated financial statements. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total Assets / Liabilities	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
September 30, 2014				
Assets:				
Natural Gas Derivatives	$0.7	$—	$0.7	$—
Liabilities:				
Natural Gas Basis Derivatives	0.6	—	0.6	—
December 31, 2013				
Assets:				
Natural Gas Derivatives	0.5	—	0.5	—
Oil Derivatives	0.3	—	0.3	—
Liabilities:				
Natural Gas Derivatives	0.7	—	0.7	—
Oil Derivatives	0.2	—	0.2	—

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

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

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

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

(8) Condensed Consolidating Financial Information

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

(9) Commitments and Contingencies

During 2014, the Company entered into additional gas transportation agreements. As of September 30, 2014, the minimum commitments under these agreements total approximately $36.3 million covering transportation from 2015 through 2020.

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/A for the year ending December 31, 2013.

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual report on Form 10-K/A for the year ended December 31, 2013. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 29 of this report.

Restatement

As discussed in the Preliminary Note and in Note 1A of the Notes to Consolidated Financial Statements included in this Form 10-Q, we are restating our unaudited condensed consolidated financial statements and related disclosures for the three and nine months ended September 30, 2013. The following discussion and analysis of our financial condition and results of operations incorporates the restated amounts. For this reason, the data set forth in this Item 2 may not be comparable to the discussion and data in our previously filed quarterly report on Form 10-Q for the quarter ended September 30, 2013.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development and are one of the largest producers of crude oil in the state of Louisiana. Oil production accounted for 29% of our third quarter 2014 production and 62% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 45% of our third quarter 2014 production and 74% of our oil and gas sales.

Recent Events and 2015 Capital Spending Plans and Expectations

- Recent crude oil price decline: Both natural gas and crude oil prices are volatile and significant price movement can impact our profitability and cash flows. Oil prices started to decline in the third quarter of 2014 and this decline accelerated during the month of October 2014. Between June 30, 2014 and October 31, 2014, WTI crude oil prices decreased 24% with the most rapid decline occurring in October 2014. Although the effect of this price decrease was somewhat muted on our third quarter results, we expect fourth quarter 2014 results will be affected in a more significant way as 60% of the Company's oil and gas sales for the first nine months of 2014 were derived from crude oil sales.

- Update of 2014 planned capital expenditures: For 2014, the Company is targeting annual production levels of 12.2 to 12.3 MMBoe with an average daily production rate of 33.4 to 33.7 MBoe/d, which is an increase from our previous expectation of 11.9 to 12.1 MMBoe. This increase is based on planned full-year capital expenditures of $390 to $400 million, which is an increase from our most recent estimate of $375 to $400 million. We will continue to fund our 2014 capital expenditures with our operating cash flow and a portion of the proceeds received from the recently closed Saka Energi transaction.

- 2015 capital spending and expectations: We expect the current significantly lower oil and natural gas prices to reduce operating cash flows and we therefore have meaningfully reduced our capital spending plans for 2015. We currently plan to spend between $240 to $260 million next year, with a focus on drilling activity in our Fasken area as well as in our South Texas oil and condensate properties. Based on this level of capital expenditures, we currently expect 2015 production to remain level with our current year average production, which is expected to average 33.4 to 33.7 MBoe/d for 2014. A portion of our capital expenditure program is discretionary and may be deferred if necessary. We forecast our capital expenditures will exceed our operating cash flows by approximately $60 to $70 million using commodity prices as of November 1, 2014. We expect to cover this level of spending through a combination of asset dispositions, joint ventures or other partnerships and will use excess proceeds to reduce borrowings on our credit facility and/or retire a portion of our long-term debt. Between June 30, 2014 and September 30, 2014, the outstanding balance under our credit facility had been reduced by approximately $100 million using a portion of the proceeds from the July 2014 closing of the Saka Energi transaction. We will continue to work with a prospective buyer for all of our Central Louisiana properties, although we remain uncertain when or if this transaction will occur. At this point, if no sale of these assets were to occur, we anticipate investing a limited amount of capital in this area during 2015 in low risk projects to maintain the value of these assets, and we will continue to consider offering portions of these properties for sale in separate parcels.

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Third Quarter 2014 Activities

- Saka Energi transaction: On July 15, 2014, we closed a transaction with Saka Energi to fully develop 8,300 acres of natural gas Eagle Ford shale properties in our Fasken area. Saka Energi purchased a 36% full participating interest in the properties for $175 million in total cash consideration, with $125 million paid at closing and $50 million in cash to be paid by Saka Energi over time to carry a portion of Swift Energy's field development costs incurred after the effective date, January 1, 2014. As of September 30, 2014, approximately $35 million remained of Saka Energi's original $50 million carry obligation, which is expected to be fulfilled by the end of calendar year 2016 but is dependent on the pace of drilling in the Fasken area. At closing, Swift received proceeds of approximately $147 million, composed of the initial $125 million in cash consideration plus Saka Energi's share of capital costs, net of revenue between the January 1, 2014 effective date and the closing date. The consideration included a $12.5 million deposit received during the prior quarter that was held in an escrow account until the closing date. The proceeds from this transaction initially were used to pay down our credit facility which were partially offset by additional borrowings against the credit facility during the quarter to fund development expenditures. We expect this transaction to allow accelerated drilling and development of our Fasken properties.

- Fasken production: In Fasken, we have grown our Eagle Ford dry gas gross production from 28.3 million cubic feet of gas per day ("MMcf/d") during the second quarter of 2013 to over 100 MMcf/d during the third quarter of 2014. We have contracted firm transportation capacity of 75 MMcf/d and have also been able to access interruptible capacity in excess of that amount during the third quarter of 2014. We also contracted for an increase in this firm transportation capacity to 160 MMcf/d, which is now in place and ready for service. We currently expect to reach our fully committed capacity production levels before the end of the first quarter of 2015.

- Production: Our production volumes decreased by 2% in the third quarter of 2014 when compared to volumes in the same period in 2013, as oil volumes decreased by 13% and NGL volumes decreased by 20%, while natural gas production volumes increased by 13%. Sequentially, production volumes decreased by 13% in the third quarter of 2014 compared to second quarter of 2014 levels as natural gas production volumes decreased by 23% (primarily due to the sale of a 36% interest in our Fasken properties to Saka Energi in July 2014), oil volumes decreased by 2% and NGL volumes increased by 11%.

- Pricing: Our weighted average sales price in the third quarter of 2014 decreased by 11% when compared to average price levels in the third quarter of 2013 and sequentially decreased 2% when compared to second quarter of 2014 average prices. When compared to pricing in the third quarter of 2013, oil prices in the third quarter of 2014 decreased 11%, NGL prices increased 5% and natural gas prices increased 13%. Sequentially over the past quarter, oil prices decreased 5%, NGL prices decreased 2% and natural gas prices decreased 15%.

- Revenues and net income: Our 2014 third quarter revenues of $138.8 million decreased 8% compared to $150.9 million for the third quarter of 2013 and sequentially decreased 11% compared to the $156.0 million of total revenues in the second quarter of 2014. Net income of $2.5 million for the third quarter of 2014 decreased from net income of $7.4 million for the third quarter of 2013 and $6.8 million in the second quarter of 2014.

- Expenses and tightening of service and supply costs: Our expenses in the third quarter of 2014 decreased $4.6 million, or 3%, compared to those in the third quarter of 2013 and sequentially decreased $10.9 million, or 8%, compared to expenses in the second quarter of 2014. We have seen some tightening in the availability of services and supplies including some upward pressure on service costs, but we believe that these costs could potentially decrease from current levels if the recent decline in oil prices continues.

Liquidity and Capital Resources

- Outstanding bank borrowings: At September 30, 2014, we had $202.0 million in outstanding borrowings under our credit facility. As of October 17, 2014, our borrowing base and commitment amount were reaffirmed at $417.6 million after being automatically reduced from $450.0 million effective July 15, 2014, due to the Saka Energi transaction. The proceeds of approximately $147 million received at closing were immediately used to pay down our outstanding borrowing under the credit facility, with additional borrowings against the credit facility during the quarter to fund development activities.

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- 2014 capital expenditures: Our capital expenditures on a cash flow basis were $317.0 million in the first nine months of 2014, compared to $435.7 million in the first nine months of 2013. The expenditures were devoted to drilling and completion activity in our South Texas core region as we drilled 16 wells in our AWP Eagle Ford field and 12 wells in our Fasken field during the year. These expenditures were funded by $252.2 million of cash provided by operating activities along with borrowings under our credit facility and proceeds from the Saka Energi transaction.

- Net cash provided by operating activities: For the first nine months of 2014, our net cash provided by operating activities was $252.2 million, representing a $26.6 million or 12% increase, compared to $225.6 million generated during the same period of 2013, primarily due to working capital changes.

- Working capital and debt to capitalization ratio: Our working capital increased from a deficit of $83.5 million at December 31, 2013, to a deficit of $50.9 million at September 30, 2014. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track its short-term financial position. Our working capital ratio does not include available liquidity through our credit facility. Our debt to capitalization ratio was 50% at September 30, 2014 and 52% at December 31, 2013.

Competitive Advantages

- Enhancing Eagle Ford asset value through operating improvements and completion technology: Our South Texas drilling activities continue to benefit from optimized well design as we are drilling longer laterals in our horizontal wells and performing more frac stages per well. 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 allowed us to drill a well in our Fasken area during the third quarter with a lateral of approximately 7,500 feet and over 20 frac stages. 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 our acreage.

- 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 per well drilling costs come down from those experienced in the prior year. For the nine months ended September 2014, our average drilling cost per well decreased to $3.1 million from $4.0 million during the prior year, even though our drilling cost per well included an average of approximately 650 more feet of lateral per well in the current year. We have also experienced efficiency gains in our hydraulic fracturing activities, lowering the overall frac cost per stage while achieving better overall results as measured by rates of return and net present value. For the nine months ended September 2014, our average per well completion cost decreased to $4.0 million from $4.2 million during the prior year, even though we are performing an average of two more frac stages per well and using approximately 270 more pounds of proppant, per lateral foot, in each stimulated stage. We believe progression along this technology learning curve is important to improving performance and reducing costs and represents a competitive, transferable skill set we can use across all of our South Texas acreage.

- Ability to capitalize on increased commodity prices in the future: Current natural gas prices are lower than historical highs but have improved from the low prices seen in recent periods. With increasing demand, including the volume of

LNG export capacity increasing over the next several years, we believe natural gas prices will increase from current levels and that selected natural gas properties can be economically developed in today's market, although much of the potential for natural gas development will require higher prices. Our Fasken properties in Webb County, which include some of the best Eagle Ford rock in South Texas as defined by porosity, total organic content and other geologic and petrophysical qualities, can be economically developed today, while areas such as our South AWP area in McMullen County may require a higher price environment to provide adequate economic returns. Our strategy includes a balanced approach to oil and natural gas, and we plan to continue development on our prolific natural gas properties, such as Fasken, along with development in economic liquids-rich areas as commodity prices improve.

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Results of Operations

Revenues — Three Months Ended September 30, 2014 and 2013

Our oil and gas sales in the third quarter of 2014 decreased by 12% compared to oil and gas sales in the third quarter of 2013, primarily due to lower oil production and prices, partially offset by higher natural gas production. Average oil prices we received were 11% lower than those received during the third quarter of 2013, while natural gas prices were 13% higher and NGL prices were 5% higher.

Crude oil production was 29% and 33% of our production volumes in the third quarters of 2014 and 2013, respectively. Crude oil sales were 62% and 70% of oil and gas sales in the third quarters of 2014 and 2013, respectively. Natural gas production was 55% and 48% of our production volumes in the third quarters of 2014 and 2013, respectively. Natural gas sales were 26% and 18% of oil and gas sales in the third quarters of 2014 and 2013, 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, 2014 and 2013:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2014	2013	2014	2013
Southeast Louisiana	$30.5	$43.9	351	438
South Texas	93.0	94.7	2,468	2,358
Central Louisiana	10.0	13.4	166	247
Other	0.4	1.0	9	14
Total	$133.9	$153.0	2,994	3,057

In the third quarter of 2014, our $19.1 million, or 12% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had an approximate $6.0 million unfavorable impact on sales due to lower oil prices partially offset by increased natural gas and NGL prices; and
- Volume variances resulted in an approximate decrease of $13 million primarily attributable to lower oil production.

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, 2014 and 2013:

	Production Volume				Average Price (1)		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended September 30, 2014	870	482	9.9	2,994	$96.12	$33.39	$3.55
Three Months Ended September 30, 2013	1,004	600	8.7	3,057	$108.17	$31.67	$3.15

(1) As described in Note 1A to the consolidated financial statements, adjustments for certain previously identified immaterial accounting errors have been
made in this Form 10-Q. Any effect on the historical unit sales prices were evaluated and deemed to be immaterial to any period presented and therefore
not restated.

For the three months ended September 30, 2014 and 2013, we recorded total net gains (losses) of $5.0 million and ($2.0 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 $97.81 and $106.32 for the third quarters of 2014 and 2013, respectively, and our average natural gas price would have been $3.91 and $3.14 for the third quarters of 2014 and 2013, respectively.

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Costs and Expenses — Three Months Ended September 30, 2014 and 2013

Our expenses in the third quarter of 2014 decreased $4.6 million, or 3%, compared to those in the third quarter of 2013, for the reasons noted below.

Lease operating cost. These expenses decreased $1.0 million, or 4%, compared to the level of such expenses in the third quarter of 2013. Lease operating costs decreased by $1.2 million, while workover expenses increased by $0.2 million. Our lease operating costs per Boe produced were $7.37 and $7.55 for the three months ended September 30, 2014 and 2013, respectively.

Transportation and gas processing. These expenses decreased $0.7 million, or 12%, compared to the level of such expenses in the third quarter of 2013, as our production mix shifted towards increased natural gas production. Our transportation and gas processing costs per Boe produced were $1.71 and $1.89 for the third quarters of 2014 and 2013, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses decreased $1.9 million, or 3% from those in the third quarter of 2013. The decrease was primarily due to decreased production and a lower per unit rate. Our DD&A rate per Boe of production was $21.82 and $22.01 in the third quarters of 2014 and 2013, respectively.

General and Administrative Expenses, Net. These expenses decreased $0.2 million, or 1%, from the level of such expenses in the third quarter of 2013. The decrease was primarily due to lower salaries and burdens and lower deferred compensation, partially offset by higher legal fees associated with the Saka Energi transaction and lower capitalized amounts. Our net general and administrative expenses per Boe produced increased to $3.67 per Boe in the third quarter of 2014 from $3.65 per Boe in the third quarter of 2013.

Severance and Other Taxes. These expenses decreased $1.5 million, or 13%, from third quarter 2013 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.6% and 7.6% in the third quarters of 2014 and 2013, respectively.

Interest. Our gross interest cost in the third quarter of 2014 was $19.4 million, of which $1.2 million was capitalized. Our gross interest cost in the third quarter of 2013 was $19.3 million, of which $1.8 million was capitalized. The decrease in the capitalized interest amount is due to a lower unproved properties balance.

Income Taxes. Our effective income tax rate increased to 54.8% from 43.3% for the third quarters of 2014 and 2013, respectively. The permanent tax differences had a larger impact on the income tax rate for the third quarter of 2014 as our income from continuing operations decreased when compared to the prior quarter.

Revenues — Nine Months Ended September 30, 2014 and 2013

Our oil and gas sales for the first nine months of 2014 were consistent with oil and gas sales in the first nine months of 2013, primarily due to higher natural gas pricing and production, offset by lower oil pricing and production. Average oil prices we received were 7% lower than those received during the first nine months of 2013, while natural gas prices were 20% higher and NGL prices were 13% higher.

Crude oil production was 29% and 34% of our production volumes in the nine months ended September 30, 2014 and 2013, respectively. Crude oil sales were 60% and 70% of oil and gas sales in the nine months ended September 30, 2014 and 2013, respectively. Natural gas production was 56% and 47% of our production volumes in the nine months ended September 30, 2014 and 2013, respectively. Natural gas sales were 29% and 18% of oil and gas sales in the nine months ended September 30, 2014 and 2013, respectively. The remaining production and sales in each period came from NGLs.

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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, 2014 and 2013:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2014	2013	2014	2013
Southeast Louisiana	$ 101.8	$ 131.8	1,119	1,346
South Texas	305.9	266.0	7,733	6,586
Central Louisiana	32.4	42.5	509	689
Other	1.4	1.7	26	33
Total	$ 441.5	$ 442.0	9,387	8,654

During the first nine months of 2014, our oil and gas sales decreased slightly by $0.5 million. The impact of lower oil prices and lower production was essentially offset by increases in both gas prices and gas production.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the nine months ended September 30, 2014 and 2013:

	Production Volume				Average Price (1)		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Nine Months Ended September 30, 2014	2,691	1,395	31.8	9,387	$ 99.08	$ 34.55	$ 3.98
Nine Months Ended September 30, 2013	2,903	1,705	24.3	8,654	$ 106.69	$ 30.48	$ 3.32

(1) As described in Note 1A to the consolidated financial statements, adjustments for certain previously identified immaterial accounting errors have been
made in this Form 10-K/A. Any effect on the historical unit sales prices were evaluated and deemed to be immaterial to any period presented and therefore
not restated.

For the nine months ended September 30, 2014 and 2013, we recorded total net gains (losses) of $2.7 million and ($0.8 million), respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $98.80 and $105.94 for the nine months ended September 30, 2014 and 2013, respectively, and our average natural gas price would have been $3.92 and $3.38 for the nine months ended September 30, 2014 and 2013, respectively.

Costs and Expenses — Nine Months Ended September 30, 2014 and 2013

Our expenses for the first nine months of 2014 increased $6.9 million, or 2%, compared to those in the first nine months of 2013, for the reasons noted below.

Lease operating cost. These expenses decreased $6.3 million, or 8%, compared to the level of such expenses in the first nine months of 2013, as our cost savings initiatives are being realized and due to the one-time costs associated with a well control incident in Lake Washington during the first half of 2013. Our lease operating costs per Boe produced were $7.52 and $8.89 for the nine months ended September 30, 2014 and 2013, respectively.

Transportation and gas processing. These expenses increased $1.0 million, or 7%, compared to the level of such expenses in the first nine months of 2013, as our production mix shifted towards increased natural gas production. Our transportation and gas processing costs per Boe produced were $1.75 and $1.78 for the nine months ended September 30, 2014 and 2013, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $13.6 million, or 7% from those in the first nine months of 2013. The increase was primarily due to higher production. Our DD&A rate per Boe of production improved to $21.42 for the nine months ended September 30, 2014, as compared to $21.67 for the nine months ended September 30, 2013.

General and Administrative Expenses, Net. These expenses decreased $1.5 million, or 4%, from the level of such expenses in the first nine months of 2013. The decrease was primarily due to lower salaries and lower deferred compensation, partially offset by lower capitalized amounts and higher legal and professional fees related to the Saka Energi transaction. Our net general and administrative expenses per Boe produced decreased to $3.58 per Boe in the first nine months of 2014 from $4.05 per Boe in the first nine months of 2013.

Severance and Other Taxes. These expenses decreased $3.4 million, or 11%, from first nine months of 2013 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.5% and 7.3% in the nine months ended September 30, 2014 and 2013, respectively. The decrease in the rate was primarily driven by higher production in South Texas which carries a lower severance tax rate than Louisiana.

Interest. Our gross interest cost in the first nine months of 2014 was $59.0 million, of which $3.7 million was capitalized. Our gross interest cost in the first nine months of 2013 was $56.9 million, of which $5.6 million was capitalized. The increase in gross interest came primarily from additional borrowings on our credit facility while the decrease in capitalized interest was due to a lower unproved properties balance.

Income Taxes. Our effective income tax rate was 49.1% and 39.9% for the nine months ended September 30, 2014 and 2013, respectively. This increase in rate related to a shortfall between the tax deduction received with respect to prior restricted stock grants that vested during the year versus the actual book expense recorded over the life of those grants.

Contractual Commitments and Obligations

Additional Commitments in 2014. During 2014, the Company entered into additional gas transportation agreements. As of September 30, 2014, the minimum commitments under these agreements total approximately $36.3 million as follows: 2015 - $6.5 million, 2016 - $7.0 million, 2017 - $7.0 million, 2018 - $6.5 million and $9.3 million thereafter. 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/A for the year ending December 31, 2013.

Critical Accounting Policies and New Accounting Pronouncements

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

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

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

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

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

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Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the future and that non-cash write-downs of oil and natural gas properties could occur in the future. For example, 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, non-cash write-downs of our oil and natural gas properties could occur in the future. We cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties.

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 December 15, 2016. We plan to review and assess the effect and implement any necessary requirements as needed.

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Forward-Looking Statements

This report includes forward-looking statements intended to qualify for the safe harbors from liability established by the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated production levels, reserve increases, capital expenditures, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this report, the words "could," "believe," "anticipate," "intend," "estimate," “budgeted”, "expect," "may," continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

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

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk factors" in Item 1A of our annual report on Form 10-K/A for the year ended December 31, 2013. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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

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

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

Interest Rate Risk. Our senior notes due in 2017, 2020 and 2022 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At September 30, 2014, we had $202.0 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.

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Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Management has determined that a deficiency in internal control over financial reporting exists related to the review of the full-cost ceiling test write-down calculation. The deficiency specifically relates to the deferred income tax effects attributable to the Company's asset retirement obligations. Management has also concluded that this deficiency is a material weakness, as defined by Securities and Exchange Commission regulations, and that our disclosure controls and procedures were not effective as of September 30, 2014 as a result of the material weakness in our internal control over financial reporting as discussed in the Preliminary Note.

In light of the material weakness referred to above, we performed additional analyses and procedures in order to conclude that our condensed consolidated financial statements in this Form 10-Q for the quarters ended September 30, 2014 and 2013 are fairly presented, in all material respects, in accordance with US GAAP.

Remediation Plan

We are remediating this material weakness by, among other things, implementing a process of enhanced review of the non-cash ceiling test calculation at September 30, 2014. The actions that we are taking are subject to ongoing senior management review and Audit Committee oversight. Management believes the foregoing efforts will effectively remediate the material weakness in the fourth quarter of 2014. As we continue to evaluate and work to improve our internal control over financial reporting, management may execute additional measures to address potential control deficiencies or modify the remediation plan described above and will continue to review and make necessary changes to the overall design of our internal controls.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first nine months of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting, except as noted above related to the full-cost ceiling test write-down calculation.

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PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

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

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 2014:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
07/01/14 – 07/31/14 (1)	—	$—	—	$—
08/01/14 – 08/31/14 (1)	3,598	$11.94	—	—
09/01/14 – 09/30/14 (1)	1,484	$10.28	—	—
Total	5,082	$11.46	—	$—

(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.

None.

Item 6. Exhibits.

10.1*	Acquisition Agreement by and between Swift Energy Operating, LLC and Saka Energi Fasken, LLC executed May 5, 2014, but effective July 15, 2014.
10.2*	Fourth Amendment and Consent to Second Amended and Restated Credit Agreement effective as of April 30, 2014, 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

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SIGNATURES

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

		SWIFT ENERGY COMPANY (Registrant)
Date:	November 17, 2014	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President Chief Financial Officer and Principal Accounting Officer

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