

SWIFT ENERGY CO  
Form 10-Q  
August 06, 2015

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

FORM 10-Q

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

For the quarterly period ended June 30, 2015  
Commission File Number 1-8754

SWIFT ENERGY COMPANY  
(Exact Name of Registrant as Specified in Its Charter)  
Texas  
(State of Incorporation)

20-3940661  
(I.R.S. Employer Identification No.)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days.

Yes  No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes  No

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  Accelerated filer  Non-accelerated filer  Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes  No

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

Common Stock 44,544,789 Shares  
(\$0.01 Par Value) (Outstanding at July 31, 2015)  
(Class of Stock)



SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2015

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## Condensed Consolidated Balance Sheets

Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	June 30, 2015 (Unaudited)	December 31, 2014
<b>ASSETS</b>		
Current Assets:		
Cash and cash equivalents	\$75	\$406
Accounts receivable	39,410	48,451
Deferred tax asset	512	6,243
Other current assets	5,315	9,569
Total Current Assets	45,312	64,669
Property and Equipment:		
Property and Equipment, including \$71,118 and \$64,903 of unproved property costs not being amortized, respectively	5,992,080	5,934,155
Less – Accumulated depreciation, depletion, and amortization	(4,704,508	) (3,839,118
Property and Equipment, Net	1,287,572	2,095,037
Other Long-Term Assets	14,144	13,641
Total Assets	\$1,347,028	\$2,173,347
<b>LIABILITIES AND STOCKHOLDERS' EQUITY</b>		
Current Liabilities:		
Accounts payable and accrued liabilities	\$45,586	\$68,244
Accrued capital costs	13,772	41,461
Accrued interest	21,497	21,389
Undistributed oil and gas revenues	12,938	17,825
Total Current Liabilities	93,793	148,919
Long-Term Debt	1,149,165	1,074,534
Deferred Tax Liabilities	512	86,376
Asset Retirement Obligation	64,977	62,122
Other Long-Term Liabilities	10,311	7,018
Commitments and Contingencies	—	—
Stockholders' Equity:		
Preferred stock, \$.01 par value, 5,000,000 shares authorized, none outstanding	—	—
Common stock, \$.01 par value, 150,000,000 shares authorized, 44,704,576 and 44,379,463 shares issued, and 44,543,976 and 43,918,029 447 shares outstanding, respectively		444
Additional paid-in capital	773,322	771,972
Treasury stock held, at cost, 160,600, and 461,434 shares, respectively	(2,487	) (9,855
Retained earnings (Accumulated deficit)	(743,012	) 31,817
Total Stockholders' Equity	28,270	794,378
Total Liabilities and Stockholders' Equity	\$1,347,028	\$2,173,347

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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
<b>Revenues:</b>				
Oil and gas sales	\$68,281	\$158,487	\$135,639	\$307,544
Price-risk management and other, net	(2,112	) (2,493	) (1,133	) (7,370
Total Revenues	66,169	155,994	134,506	300,174
<b>Costs and Expenses:</b>				
General and administrative, net	10,290	12,058	22,846	22,584
Depreciation, depletion, and amortization	42,088	73,090	102,786	135,741
Accretion of asset retirement obligation	1,381	1,415	2,746	2,801
Lease operating cost	17,164	23,572	36,198	48,539
Transportation and gas processing	5,086	6,013	10,409	11,305
Severance and other taxes	4,424	9,436	9,556	18,638
Interest expense, net	18,741	18,649	36,969	37,098
Write-down of oil and gas properties	260,504	—	763,073	—
Total Costs and Expenses	359,678	144,233	984,583	276,706
Income (Loss) Before Income Taxes	(293,509	) 11,761	(850,077	) 23,468
Provision (Benefit) for Income Taxes	(642	) 4,934	(80,133	) 11,199
Net Income (Loss)	\$(292,867	) \$6,827	\$(769,944	) \$12,269
<b>Per Share Amounts-</b>				
Basic: Net Income (Loss)	\$(6.58	) \$0.16	\$(17.35	) \$0.28
Diluted: Net Income (Loss)	\$(6.58	) \$0.15	\$(17.35	) \$0.28
Weighted Average Shares Outstanding - Basic	44,516	43,826	44,374	43,727
Weighted Average Shares Outstanding - Diluted	44,516	44,312	44,374	44,215

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 (Accumulated Deficit)	Total
Balance, December 31, 2013	\$439	\$762,242	\$(12,575)	\$315,244	\$1,065,350
Stock issued for benefit plans (154,665 shares)	—	(1,876)	3,785	—	1,909
Purchase of treasury shares (102,673 shares)	—	—	(1,065)	—	(1,065)
Employee stock purchase plan (71,825 shares)	1	823	—	—	824
Issuance of restricted stock (392,292 shares)	4	(4)	—	—	—
Amortization of share-based compensation	—	10,787	—	—	10,787
Net Loss	—	—	—	(283,427)	(283,427)
Balance, December 31, 2014	\$444	\$771,972	\$(9,855)	\$31,817	\$794,378
Stock issued for benefit plans (352,476 shares) (1)	—	(1,714)	7,518	(4,885)	919
Purchase of treasury shares (51,642 shares) (1)	—	—	(150)	—	(150)
Employee stock purchase plan (87,629 shares) (1)	1	301	—	—	302
Issuance of restricted stock (237,484 shares) (1)	2	(2)	—	—	—
Amortization of share-based compensation (1)	—	2,765	—	—	2,765
Net Loss (1)	—	—	—	(769,944)	(769,944)
Balance, June 30, 2015 (1)	\$447	\$773,322	\$(2,487)	\$(743,012)	\$28,270

(1) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Six Months Ended June 30,		
	2015	2014	
Cash Flows from Operating Activities:			
Net income (loss)	\$ (769,944	) \$ 12,269	
Adjustments to reconcile net income (loss) to net cash provided by operating activities-			
Depreciation, depletion, and amortization	102,786	135,741	
Write-down of oil and gas properties	763,073	—	
Accretion of asset retirement obligation	2,746	2,801	
Deferred income taxes	(80,133	) 11,199	
Share-based compensation expense	2,153	3,683	
Other	3,606	(2,439	)
Change in assets and liabilities-			
(Increase) decrease in accounts receivable and other current assets	9,041	1,360	
Increase (decrease) in accounts payable and accrued liabilities	(3,997	) 5,895	
Increase (decrease) in income taxes payable	—	(150	)
Increase (decrease) in accrued interest	108	(56	)
Net Cash Provided by Operating Activities	29,439	170,303	
Cash Flows from Investing Activities:			
Additions to property and equipment	(104,997	) (208,979	)
Proceeds from the sale of property and equipment	946	35	
Net Cash Used in Investing Activities	(104,051	) (208,944	)
Cash Flows from Financing Activities:			
Proceeds from bank borrowings	180,500	195,800	
Payments of bank borrowings	(105,800	) (159,800	)
Net proceeds from issuances of common stock	302	824	
Purchase of treasury shares	(150	) (896	)
Payments of debt issuance costs	(571	) —	
Net Cash Provided by Financing Activities	74,281	35,928	
Net decrease in Cash and Cash Equivalents	(331	) (2,713	)
Cash and Cash Equivalents at Beginning of Period	406	3,277	
Cash and Cash Equivalents at End of Period	\$ 75	\$ 564	
Supplemental Disclosures of Cash Flows Information:			
Cash paid during period for interest, net of amounts capitalized	\$ 35,488	\$ 36,031	
Cash paid during period for income taxes	\$ —	\$ 150	
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 for the fiscal year ended December 31, 2014 as filed with the Securities and Exchange Commission on March 2, 2015.

(2) Summary of Significant Accounting Policies

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

**Use of Estimates.** The preparation of financial statements in conformity with accounting principles generally accepted in the United States (“GAAP”) requires us to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and the reported amounts of certain revenues and expenses during each reporting period. We believe our estimates and assumptions are reasonable; however, such estimates and assumptions are subject to a number of risks and uncertainties that may cause actual results to differ materially from such estimates. Significant estimates and assumptions underlying these financial statements include:

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties, the related present value of estimated future net cash flows there-from, and the ceiling test impairment calculation,
- estimates related to the collectability of accounts receivable and the credit worthiness of our customers,
- estimates of the counterparty bank risk related to letters of credit that our customers may have issued on our behalf,
- estimates of future costs to develop and produce reserves,
- accruals related to oil and gas sales, capital expenditures and lease operating expenses,
- estimates of insurance recoveries related to property damage, and the solvency of insurance providers,
- estimates in the calculation of share-based compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- the estimated future cost and timing of asset retirement obligations,
- estimates made in our income tax calculations,
- estimates in the calculation of the fair value of hedging assets and liabilities, and
- estimates in the assessment of current litigation claims against the company.

While we are not aware of any material revisions to any of our estimates, there will likely be future revisions to our estimates resulting from matters such as new accounting pronouncements, changes in ownership interests, payouts,

joint venture audits, re-allocations by purchasers or pipelines, or other corrections and adjustments common in the oil and gas industry, many 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.

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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 June 30, 2015 and 2014, such internal costs capitalized totaled \$3.3 million and \$6.9 million, respectively. For the six months ended June 30, 2015 and 2014, such internal costs capitalized totaled \$7.0 million and \$14.1 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties (refer to Note 5 of these consolidated financial statements for further discussion on capitalized interest costs).

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

(in thousands)	June 30, 2015	December 31, 2014
Property and Equipment		
Proved oil and gas properties	\$ 5,876,399	\$ 5,826,995
Unproved oil and gas properties	71,118	64,903
Furniture, fixtures, and other equipment	44,563	42,257
Less – Accumulated depreciation, depletion, and amortization	(4,704,508 )	(3,839,118 )
Property and Equipment, Net	\$ 1,287,572	\$ 2,095,037

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

Future development costs are estimated on a property-by-property basis based on current economic conditions and are amortized to expense as our capitalized oil and gas property costs are amortized.

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

Geological and geophysical (“G&G”) costs incurred on developed properties are recorded in “Proved properties” and therefore subject to amortization. G&G costs incurred that are directly associated with specific unproved properties are capitalized in “Unproved properties” and evaluated as part of the total capitalized costs associated with a prospect. The cost of unproved properties not being amortized is assessed quarterly, on a property-by-property basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we

evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, and available geological and geophysical information. Any impairment assessed is added to the cost of proved properties being amortized.

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

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on the first day of each month, adjusted for price differentials, discounted at 10%, and the lower of cost or fair value of unproved properties) adjusted for related income tax effects (“Ceiling Test”).

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

Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, for the three and six months ended June 30, 2015, we reported a non-cash impairment write-down, on a before-tax basis, of \$260.5 million and \$763.1 million, respectively, on our oil and natural gas properties.

If future capital expenditures out pace future discounted net cash flows in our reserve calculations, if we have significant declines in our oil and natural gas reserves volumes (which also reduces our estimate of discounted future net cash flows from proved oil and natural gas reserves) or if oil or natural gas prices decline or remain at levels prevalent in the current period, it is likely that non-cash write-downs of our oil and natural gas properties will occur in the future. We cannot control and cannot predict what future prices for oil and natural gas will be, thus we cannot estimate the amount or timing of any potential future non-cash write-down of our oil and natural gas properties due to decreases in oil or natural gas prices. However, due to current trends in commodity pricing it is likely that we will record additional ceiling test write-downs in future periods.

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

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

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

At June 30, 2015, our “Accounts receivable” balance included \$27.2 million for oil and gas sales, \$7.5 million for joint interest owners, \$3.2 million for severance tax credit receivables and \$1.6 million for other receivables. At December 31, 2014, our “Accounts receivable” balance included \$34.8 million for oil and gas sales, \$8.4 million for joint interest owners, \$3.1 million for severance tax credit receivables and \$2.2 million for other receivables.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate, including our wells, in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to “General and administrative, net”, on the accompanying condensed consolidated statements of operations. Our supervision fees are allocated to each well based on general and administrative costs incurred for well maintenance and support. The

amount of supervision fees charged for the three and six months ended June 30, 2015 and 2014 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated were \$2.2 million and \$3.0 million for the three months ended June 30, 2015 and 2014, respectively and \$4.9 million and \$5.7 million for the six months ended June 30, 2015 and 2014, respectively.

Other Current Assets. Included in "Other current assets" on the accompanying condensed consolidated balance sheets are inventories which consist primarily of tubulars and other equipment and supplies that we expect to place in service in production operations. Our inventories are recorded at cost (weighted average method) and totaled \$0.8 million at June 30, 2015 and \$3.1 million at December 31, 2014.

For the three months ended June 30, 2015, we recorded a charge of \$2.1 million, related to inventory obsolescence in "Price-risk management and other, net" on the accompanying condensed statement of operations.

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Also included in "Other current assets" on the accompanying condensed consolidated balance sheets are prepaid expenses totaling \$4.1 million and \$3.9 million at June 30, 2015 and December 31, 2014, respectively. These prepaid amounts cover well insurance, drilling contracts and various other prepaid expenses.

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

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

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

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

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

	June 30, 2015	December 31, 2014
Trade accounts payable (1)	\$ 12,361	\$ 31,153
Accrued operating expenses	8,352	10,784
Accrued compensation costs	7,432	8,715
Asset retirement obligation – current portion	7,197	10,709
Accrued taxes	5,385	2,957
Other payables	4,859	3,926
Total accounts payable and accrued liabilities	\$ 45,586	\$ 68,244

(1) Included in "trade accounts payable" are liabilities of approximately \$1.6 million and \$13.7 million at June 30, 2015 and December 31, 2014, respectively, for outstanding checks.

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

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

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



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

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

### (3) Share-Based Compensation

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

We receive a tax deduction for certain stock option exercises during the period the stock options are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards. We receive an additional tax deduction when restricted stock awards vest at a higher value than the value used to recognize compensation expense at the date of grant. We are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the three months ended June 30, 2015 and 2014, we recognized an income tax shortfall in earnings of \$0.2 million, and for the six months ended June 30, 2015 and 2014, we recognized an income tax shortfall in earnings of \$1.4 million and \$1.9 million, respectively, primarily related to restricted stock awards that vested at a price lower than the grant date fair value.

Share-based compensation expense for awards issued to both employees and non-employees, which was recorded in "General and administrative, net" in the accompanying condensed consolidated statements of operations, was \$1.2 million and \$1.7 million for the three months ended June 30, 2015 and 2014, respectively, and \$2.0 million and \$3.3 million for the six months ended June 30, 2015 and 2014, respectively. Share-based compensation recorded in lease operating cost was less than \$0.1 million for the three months ended June 30, 2015 and 2014 and \$0.1 million for the six months ended June 30, 2015 and 2014. We also capitalized \$0.4 million and \$0.9 million of share-based compensation for the three months ended June 30, 2015 and 2014, respectively, and capitalized \$0.7 million and \$2.0 million for the six months ended June 30, 2015 and 2014, respectively. We view stock option awards and restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life of component awards and 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 six months ended June 30, 2015, there were 1,800 stock option awards that expired leaving 1,330,390 stock option

awards outstanding at June 30, 2015. There was no other activity relating to our stock option awards during the six months ended June 30, 2015.

As of June 30, 2015 our stock option awards outstanding and exercisable had no aggregate intrinsic value since all outstanding stock option awards were out of the money, and we did not have any remaining unrecognized compensation cost related to stock option awards. At June 30, 2015, the weighted average contract life of stock option awards outstanding and exercisable was 4.3 years.

#### Restricted Stock Awards

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

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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 June 30, 2015, we had unrecognized compensation expense of \$6.4 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 six months ended June 30, 2015 was \$5.2 million.

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

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	1,414,012	\$ 14.81
Restricted shares granted	609,238	\$ 2.64
Restricted shares canceled	(189,723 )	\$ 14.42
Restricted shares vested	(237,484 )	\$ 21.77
Restricted shares outstanding, end of period	1,596,043	\$ 9.17

## Performance-Based Restricted Stock Units

For the six months ended June 30, 2015, the Company granted 216,450 units of performance-based restricted stock units containing market conditions that require the price of our common stock to increase to \$5.22 per share by December 31, 2017, the end of the performance period, before any payout is achieved. These units were granted at 100% of the target payout level with conditions of the grants allowing for a payout ranging between no payout and 200% of target. The compensation expense for these awards is based on the per unit grant date valuation using a Monte-Carlo simulation multiplied by the target payout level. The payout level is calculated based on actual stock price performance achieved during the performance period. The awards have a cliff vesting period of 3.0 years.

As of June 30, 2015, we had unrecognized compensation expense of \$1.4 million related to our restricted stock units, which is expected to be recognized over a weighted-average period of 1.8 years. No shares vested during the six months ended June 30, 2015 and 2014. The weighted average grant date fair value for the restricted stock units granted during six months ended June 30, 2015 was \$1.98 per unit.

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

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

## Cash-Settled Restricted Stock Units (Liability Awards)

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



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## (4) Earnings Per Share

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

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

	Three Months Ended June 30, 2015			Three Months Ended June 30, 2014		
	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	\$ (292,867 )	44,516	\$ (6.58 )	\$ 6,827	43,826	\$ 0.16
Dilutive Securities:						
Restricted Stock Awards		—			429	
Restricted Stock Units		—			57	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	\$ (292,867 )	44,516	\$ (6.58 )	\$ 6,827	44,312	\$ 0.15
	Six Months Ended June 30, 2015			Six Months Ended June 30, 2014		
	Net Loss	Shares	Per Share Amount	Net Loss	Shares	Per Share Amount
Basic EPS:						
Net Income (Loss) and Share Amounts	\$ (769,944 )	44,374	\$ (17.35 )	\$ 12,269	43,727	\$ 0.28
Dilutive Securities:						
Restricted Stock Awards		—			424	
Restricted Stock Units		—			64	
Diluted EPS:						
Net Income (Loss) and Assumed Share Conversions	\$ (769,944 )	44,374	\$ (17.35 )	\$ 12,269	44,215	\$ 0.28

Approximately 1.3 million and 1.4 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended June 30, 2015 and 2014 because they were antidilutive, while 1.3 million and 1.5 million stock options to purchase shares were not included in the computation of Diluted EPS for the six months ended June 30, 2015 and 2014, because these stock options were antidilutive.

Approximately 0.7 million and 0.3 million restricted stock awards for the three months ended June 30, 2015 and 2014, respectively, and approximately 0.7 million and 0.3 million restricted stock awards for the six months ended June 30, 2015 and 2014, respectively, were not included in the computation of Diluted EPS because they were antidilutive.

Approximately 1.2 million and 0.7 million shares for the three months ended June 30, 2015 and 2014, respectively, and approximately 1.2 million and 0.7 million shares for the six months ended June 30, 2015 and 2014, respectively, related to

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performance-based restricted stock units that could be converted to common shares based on predetermined performance and market goals were not included in the computation of Diluted EPS because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the performance period.

## (5) Long-Term Debt

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

	June 30, 2015	December 31, 2014
7.125% senior notes due in 2017	\$ 250,000	\$ 250,000
8.875% senior notes due in 2020 (1)	222,951	222,775
7.875% senior notes due in 2022 (1)	404,214	404,459
Bank Borrowings due in 2017	272,000	197,300
Long-Term Debt (1)	\$ 1,149,165	\$ 1,074,534

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

As of June 30, 2015, we had \$272.0 million of outstanding bank borrowings on our credit facility which has a maturity date of November 1, 2017. The maturities on our senior notes are \$250.0 million in 2017, \$225.0 million in 2020 and \$400.0 million in 2022.

We had capitalized interest on our unproved properties in the amount of \$1.2 million for the three months ended June 30, 2015 and 2014, respectively. We had capitalized interest on our unproved properties in the amount of \$2.4 million and \$2.5 million for the six months ended June 30, 2015 and 2014, respectively.

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

The 7.125% senior notes due in 2017 mature on June 1, 2017, and the balance of their issuance costs at June 30, 2015, was \$1.0 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at June 30, 2015, was \$2.8 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at June 30, 2015, was \$5.6 million.

The balance of our revolving credit facility issuance costs at June 30, 2015, was \$2.2 million. This balance includes the impact of the credit facility amendments (as noted below) on May 1, 2015, which resulted in the capitalization of an additional \$0.6 million of issuance costs as well as the write-down of previously unamortized debt issuance costs of \$0.2 million.

Bank Borrowings. Effective May 1, 2015, we executed an amendment to our credit facility agreement lowering our borrowing base and commitment amount and changing our financial covenant ratios as noted below. Our syndicate of 11 banks decreased the borrowing base and commitment amount under our credit facility from \$417.6 million to \$375.0 million while the maturity date of November 1, 2017 remained unchanged.

We had \$272.0 million and \$197.3 million in outstanding borrowings under our credit facility at June 30, 2015 and December 31, 2014, respectively. As of June 30, 2015, the interest rate on our credit facility was either (a) the lead bank's prime rate plus an applicable margin or (b) the Eurodollar rate plus an applicable margin. However with respect to (a), if the lead bank's prime rate was not higher than each of the federal funds rate plus 0.5%, and the adjusted London Interbank Offered Rate ("LIBOR") plus 1%, the greatest of these three rates then applied. The applicable margins vary depending on the level of outstanding debt with escalating rates of 75 to 175 basis points above the Alternative Base Rate and escalating rates of 175 to 275 basis points for Eurodollar rate loans. At June 30, 2015, the

lead bank's prime rate was 3.25%. The commitment fee terms associated with the credit facility was 0.50% for the three months ended June 30, 2015.

At June 30, 2015, the terms of our credit facility included, among other restrictions, a limitation on the level of cash dividends (not to exceed \$15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of \$50.0 million, and limitations on incurring other debt. At June 30, 2015, our bank credit agreement contained financial covenants detailing certain minimum financial ratios that must be maintained. The first (which was not amended on May 1, 2015) was an adjusted working capital ratio of adjusted current assets to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0, which was met at June 30, 2015 as the Company's ratio at that date was 1.6 to 1.0. The second ratio was an interest coverage



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ratio (as amended on May 1, 2015), calculated on a trailing twelve month basis of EBITDAX to interest expense (as defined in the Credit Agreement), of no less than 1.50 to 1.0, which was met at June 30, 2015 as the Company's ratio at that date was 3.0 to 1.0. The ratio returns to the original requirement of 2.75 to 1.0 in 2017 and later periods. The third ratio was a new senior secured leverage ratio (as defined in the Credit Agreement, effective on May 1, 2015 and expiring after the fourth quarter of 2016), requiring that the ratio of senior secured liabilities on the last day of the quarter to EBITDAX, calculated on a trailing twelve month basis, not be greater than 3.0 to 1.0 through the end of the second quarter of 2016 (nor greater than 2.5 to 1.0 for the last two quarters of 2016), which was met as the Company's June 30, 2015 ratio was 1.2 to 1.0. The amendment also added a new liquidity requirement (as defined in the Credit Agreement) effective July 1, 2015, which effectively requires that at the date of any payment of interest in respect to the existing senior notes or any new debt (after giving effect to such interest payment), the unused borrowing base may not be less than 15% of the commitment amount then in effect. Based upon our projections of production and current commodity futures prices, we believe we will be in compliance with these financial covenant ratios up to November 1, 2015 (the date of our next semi-annual borrowing base redetermination).

Since inception, no cash dividends have been declared on our common stock. The terms of the credit facility also require us to secure the facility with collateral equal to at least 75% of our oil and natural gas properties. Under the terms of the credit facility, the commitment amount can be less than or equal to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time. As of June 30, 2015, we were in compliance with the provisions of this agreement.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled \$2.2 million and \$2.1 million for the three months ended June 30, 2015 and 2014, respectively, and totaled \$4.0 million and \$4.2 million for the six months ended June 30, 2015 and 2014, respectively. The amount of commitment fees included in interest expense, net was \$0.1 million and \$0.2 million for the three months ended June 30, 2015 and 2014, respectively, and was \$0.4 million and \$0.3 million for the six months ended June 30, 2015 and 2014, respectively.

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

investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of June 30, 2015.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled \$7.9 million for the three months ended June 30, 2015 and 2014 and \$15.8 million for the six months ended June 30, 2015 and 2014.

Senior Notes Due In 2020. These notes consist of \$225.0 million of 8.875% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9.125%. The notes were issued on November 25, 2009 with an original discount of \$3.6 million and will mature on January 15, 2020. The original discount of \$3.6 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing

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such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on January 15, 2010. We may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. We incurred approximately \$5.0 million of debt issuance costs related to these notes, which is included in "Other Long-Term Assets" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of June 30, 2015.

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 June 30, 2015 and 2014 and \$10.4 million for the six months ended June 30, 2015 and 2014.

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

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled \$4.6 million for the three months ended June 30, 2015 and 2014 and \$9.2 million and \$9.1 million for the six months ended June 30, 2015 and 2014, respectively.

(6) Acquisitions and Dispositions

There were no material acquisitions or dispositions in the six months ended June 30, 2015 and 2014.

(7) Price-Risk Management Activities

The Company follows FASB ASC 815-10, which requires that changes in the derivative's fair value are recognized in earnings. The changes in the fair value of our derivatives are recognized in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. We have a price-risk management policy to use

derivative instruments to protect against declines in oil and natural gas prices, mainly through the purchase of price swaps, floors, calls, collars and participating collars.

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

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

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At June 30, 2015, we also had an immaterial amount of payables for settled derivatives recognized on the accompanying condensed consolidated balance sheet in "Accounts payable and accrued liabilities", which were subsequently paid in July 2015.

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for our derivative contracts. This is an industry standardized contract containing the general conditions of our derivative transactions including provisions relating to netting derivative settlement payments under certain circumstances (such as default). For reporting purposes, the Company has elected to not offset the asset and liability fair value amounts of its derivatives on the accompanying balance sheets. If all counterparties were in a default situation, the Company, under the right of set-off, would have shown a net derivative fair value asset of \$0.1 million at June 30, 2015. For further discussion related to the fair value of the Company's derivatives, refer to Note 8 of these condensed consolidated financial statements.

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

Natural Gas Basis Derivatives (East Texas Houston Ship Channel Settlements) 2015 Contracts	Total Volumes (MMBtu)	Swap Fixed Price
Swaps	3,060,000	\$(0.016 )

## (8) Fair Value Measurements

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

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

	June 30, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	\$ 141.9	\$ 250.0	\$ 153.0	\$ 250.0
8.875% senior notes due in 2020	\$ 96.1	\$ 223.0	\$ 133.1	\$ 222.8
7.875% senior notes due in 2022	\$ 157.2	\$ 404.2	\$ 198.0	\$ 404.5

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

The following table presents our assets and liabilities that are measured at fair value as of June 30, 2015 and December 31, 2014, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 7 of these condensed consolidated financial statements. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total Assets / (Liabilities)	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
June 30, 2015				
Assets:				
Natural Gas Basis				
Derivatives	\$0.1	\$—	\$0.1	\$—
December 31, 2014				
Assets:				
Natural Gas Derivatives	2.4	—	2.4	—
Natural Gas Basis	0.1	—	0.1	—
Derivatives				
Liabilities:				
Natural Gas Basis	0.1	—	0.1	—
Derivatives				

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

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

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

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

#### (9) Asset Retirement Obligations

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

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

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	2015
Asset Retirement Obligations recorded as of January 1	\$ 72,831
Accretion expense	2,746
Liabilities incurred for new wells and facilities construction	142
Reductions due to sold and abandoned wells and facilities	(3,515 )
Revisions in estimates	(31 )
Asset Retirement Obligations as of June 30	\$ 72,173

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At June 30, 2015 and December 31, 2014, approximately \$7.2 million and \$10.7 million of our asset retirement obligations were classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

(10) Condensed Consolidating Financial Information

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

(11) Commitments and Contingencies

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

During the second quarter of 2015, the Company entered into an additional gas transportation agreement covering transportation from 2016 to 2020. The agreement increased our minimum contractual obligations, over the amounts reported in our Annual Report on Form 10-K for the year ending December 31, 2014 by approximately \$39 million, with no change to our obligations during 2015. Refer to Management's Discussion and Analysis of these condensed consolidated financial statements for further discussion.

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



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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 for the year ended December 31, 2014. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 28 of this report.

Overview

We are an independent oil and natural gas company formed in 1979 engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our South Texas properties as well as onshore and inland waters of Louisiana. We hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development. Natural gas production accounted for 65% of our second quarter of 2015 production and 40% of our oil and gas sales while oil constituted 22% of our second quarter of 2015 production and 52% of our oil and gas sales.

The significant decline in crude oil and natural gas prices has affected our business: Oil prices have declined since the end of 2014, with our average oil prices received falling from approximately \$72 per barrel during the fourth quarter of 2014 to approximately \$45 per barrel in the first quarter of 2015, recovering modestly to approximately \$57 per barrel in the second quarter of 2015. However, in July 2015 average oil prices have declined to approximately \$51 per barrel (as measured using the WTI crude oil price). Natural gas prices have also fallen during the same period, although to a lesser extent, with our average natural gas prices received falling from \$3.58 per Mcf during the fourth quarter of 2014 to \$2.53 per Mcf in the first quarter of 2015 and \$2.40 per Mcf in the second quarter of 2015. In July 2015, average natural gas prices, as measured using Henry Hub spot prices, have increased to \$2.84 per MMBtu. The effect of these price decreases was significant for our first and second quarter of 2015 results and for our financial condition. Our cash flows, operating results, future growth prospects and financial condition could continue to be negatively impacted if lower crude oil and natural gas prices persist.

**2015 planned capital expenditures:** Recent lower oil and natural gas prices have reduced operating cash flows and, as a result, we have meaningfully reduced our capital spending plans for 2015 compared to 2014 levels. The Company is targeting annual production levels of 11.5 to 11.6 MMBoe based on planned full-year capital expenditures of \$110 to \$120 million, with a primary focus on drilling activity in our dry gas Fasken area in Webb County and our South AWP area in McMullen County. A portion of our capital expenditure program is discretionary and may be further deferred, if necessary. We currently expect to fund 2015 capital expenditures with operating cash flow, potential credit facility borrowings and possibly proceeds from any asset dispositions, joint ventures or other similar arrangements.

**2015 cost reduction initiatives:** We continue taking significant actions to reduce our future capital, operating and overhead costs. During the first six months of 2015 we have reduced drilling and completion costs and terminated one of our drilling contracts. In conjunction with the reduction in our capital spending plans for 2015, we continue to negotiate with all of our primary suppliers and service companies to reduce our capital and operating cost structures. These initiatives have already helped us recognize a meaningful reduction during the first six months of 2015, with our lease operating expenses, excluding workover costs, decreasing from \$20.9 million in the second quarter of 2014 to \$18.6 million in the first quarter of 2015 and \$17.2 million in the second quarter of 2015. By focusing operations in our high quality Fasken and AWP areas, we will continue to reduce our development costs by taking advantage of existing infrastructure and experienced operating personnel. During 2015 the Company also implemented various cost savings efforts including a significant headcount reduction and the signing of a new lease agreement for reduced corporate office space. As a result of these changes, our general and administrative costs have decreased from \$12.1 million in the second quarter of 2014, and \$12.6 million in the first quarter of 2015, to \$10.3 million in the second

quarter of 2015. These changes will allow us to continue recognizing a meaningful reduction in costs through the end of the year and provide prospective sustained lower overhead costs.

#### Second Quarter 2015 Operating Highlights

Increasing capacity and enhancing asset value in the Eagle Ford: The Company recently secured an additional 30 MMcf per day of firm capacity out of the Fasken area, which is anticipated to be in place by the end of August. The Company now has total firm capacity of 190 MMcf per day to support continued development of the Eagle Ford in its Webb County acreage.

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

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

Improved value of Eagle Ford shale assets through reductions in per well costs: We have seen improved performance this year in our initial production (IP) rates for Eagle Ford wells and have also seen our 2015 average per well drilling costs decrease to \$2.6 million from an average per well cost of \$3.4 million during 2014. We have also experienced efficiency gains in our hydraulic fracturing activities, lowering the overall frac cost per stage while performing more frac stages per well, using additional proppant in each stimulated stage and achieving better overall results as measured by rates of return and net present value. The combined drilling and completion costs per well for the first six months of 2015 have been reduced to \$6.3 million, on average, significantly below the prior year average cost per well.

Second quarter 2015 revenues and net loss: Our second quarter oil and gas revenues decreased 57%, or \$90.2 million, when compared to second quarter of 2014 revenues, primarily due to the impact of lower oil and natural gas pricing (which decreased 44% and 42%, respectively) and lower oil production in our AWP and Lake Washington fields. Our net loss of \$292.9 million for the second quarter of 2015 is primarily due to the \$260.5 million non-cash write-down of our oil and gas properties.

## Liquidity and Capital Resources

2015 borrowing base redeterminations and credit facility financial covenants: As part of our regularly scheduled May 2015 borrowing base redetermination, our revolving credit facility borrowing base and commitment amounts were reduced to \$375.0 million from \$417.6 million primarily due to the continuation of depressed oil and gas prices.

Additionally, the revolving credit facility has been amended to provide for revised financial covenants (see Note 5 of these condensed consolidated financial statements for more information), including:

The ratio of EBITDAX to Interest Expense (the interest coverage ratio) being reduced for the remainder of 2015 and all of 2016 to 1.5 to 1.0, and then returning to its previous minimum ratio of 2.75 to 1.0 thereafter.

A new senior secured leverage ratio being added, requiring a minimum ratio of senior secured liabilities to EBITDAX of 3.0 to 1.0 for the remainder of 2015 and the first half of 2016, and 2.5 to 1.0 for the last half of 2016, with the covenant no longer being in place for 2017 and later periods.

A new liquidity covenant being added effective July 1, 2015, which effectively requires that at the date of any payment of interest in respect to the existing senior notes or any new debt (after giving effect to such interest payments), the unused borrowing base may not be less than 15% of the commitment amount then in effect.

As of June 30, 2015, we were in compliance with the financial covenant ratios (we were also in compliance with the liquidity covenant as of our most recent interest payment in July of 2015). Based upon our projections of production and current commodity futures prices, we believe we will be in compliance with these financial covenant ratios up to

November 1, 2015 (the date of our next semi-annual borrowing base redetermination).

If we experience the continuation of low oil and gas prices, or if they decline even further, we anticipate that our existing revolving credit facility borrowing base and commitment amounts will be reduced further (on the date of our next borrowing base redetermination) from the current \$375.0 million and/or we may need to amend our current financial covenants. We are focused on our balance sheet and additional financing opportunities and options to reduce our reliance on our revolving credit facility and improve Swift Energy's long-term liquidity, including additional capital alternatives in the marketplace along with capital that might be made available through joint ventures or similar cost-sharing arrangements.

Outstanding bank borrowings and liquidity for the remainder of 2015: As noted above, effective May 1, 2015, we executed an amendment to our credit facility, lowering our borrowing base and commitment amount from \$417.6 million to \$375.0 million. At June 30, 2015 and July 31, 2015, we had \$272.0 million and \$278.1 million, respectively, in outstanding borrowings

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under our credit facility, leaving us with availability to borrow approximately \$101 million and \$95 million (excluding \$1.6 million in letters of credit), respectively. We plan to control our liquidity during the remainder of 2015 by maintaining a reduced level of capital expenditures to match market expectations of reduced commodity prices.

On June 23, 2015, we launched the offering of a \$640 million first-lien term loan, the marketing of which is being reassessed in the face of unfavorable conditions in both global and domestic debt markets. The first-lien term loan was one of the many options that we considered to secure liquidity to execute our business plan through the next two to three years. We have retained Lazard Freres & Co. LLC to advise the Company's management and Board of Directors with respect to realigning our balance sheet including our senior notes which trade at levels significantly below face value, addressing certain maturities, and enhancing our liquidity profile.

2015 capital expenditures: Our capital expenditures on a cash flow basis were \$105.0 million in the first six months of 2015, compared to \$209.0 million in the first six months of 2014. The expenditures during the current period, which were \$58.9 million on an accrual basis, were primarily devoted to developmental drilling and completion activity in our South Texas core region as we drilled one well in our AWP Eagle Ford field and 10 wells in our Fasken field, in addition to cash payments made during the current period related to amounts accrued during the prior year for drilling and completion activities. These expenditures were funded by approximately \$75 million of net borrowings under our credit facility along with operating cash flows.

Net cash provided by operating activities: For the first six months of 2015, our net cash provided by operating activities was \$29.4 million, representing a \$140.9 million decrease, compared to \$170.3 million generated during the same period of 2014, primarily due to lower commodity prices and decreased oil production, partially offset by lower operating costs.

Contractual Commitments and Obligations

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

We had no other material changes in our contractual commitments and obligations from amounts referenced under "Contractual Commitments and Obligations" in Management's Discussion and Analysis in our Annual Report on Form 10-K for the year ending December 31, 2014.

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## Results of Operations

## Revenues — Three Months Ended June 30, 2015 and 2014

Our oil and gas sales in the second quarter of 2015 decreased by 57% compared to oil and gas sales in the second quarter of 2014, primarily due to overall lower commodity pricing as well as overall lower production. Average oil prices we received were 44% lower than those received during the second quarter of 2014, while natural gas prices were 42% lower and NGL prices were 55% lower.

Crude oil production was 22% and 26% of our production volumes in the second quarters of 2015 and 2014, respectively. Crude oil sales were 52% and 57% of oil and gas sales in the second quarters of 2015 and 2014, respectively. Natural gas production was 65% and 62% of our production volumes in the second quarters of 2015 and 2014, respectively. Natural gas sales were 40% and 33% of oil and gas sales in the second quarters of 2015 and 2014, respectively. The remaining production and sales in each period came from NGLs.

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

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2015	2014	2015	2014
Artesia Wells	\$ 5.5	\$ 16.3	292	440
AWP	25.5	62.4	997	1,139
Fasken (1)	16.9	32.4	1,107	1,272
Other South Texas	0.9	2.1	47	65
Total South Texas	48.8	113.2	2,443	2,916
Southeast Louisiana	14.0	33.9	278	367
Central Louisiana	5.2	10.8	146	158
Other	0.3	0.6	8	8
Total	\$ 68.3	\$ 158.5	2,875	3,449

(1) Fasken amounts for the second quarter of 2014 include approximately \$11.6 million (458 MBoe) representing interests sold to Saka Energi effective July 15, 2014.

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

In the second quarter of 2015, our \$90.2 million, or 57% decrease in oil, NGL, and natural gas sales resulted from:

• Price variances that had an approximate \$55.2 million unfavorable impact on sales due to overall lower commodity pricing; and

• Volume variances that had a \$35.0 million unfavorable impact on sales due to overall lower production.



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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 June 30, 2015 and 2014:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended June 30, 2015	628	366	11.3	2,875	\$ 56.65	\$ 15.18	\$ 2.40
Three Months Ended June 30, 2014	890	434	12.7	3,449	\$ 101.67	\$ 33.93	\$ 4.16

For the three months ended June 30, 2015 and 2014, we recorded total net losses of \$0.1 million and \$2.7 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been \$56.65 and \$100.16 for the second quarters of 2015 and 2014, respectively, and our average natural gas price would have been \$2.40 and \$4.05 for the second quarters of 2015 and 2014, respectively.

#### Costs and Expenses — Three Months Ended June 30, 2015 and 2014

Our expenses in the second quarter of 2015 increased \$215.4 million, compared to those in the second quarter of 2014, for the reasons noted below. Excluding the 2015 ceiling test write-down, our expenses in the second quarter of 2015 decreased \$45.1 million, or 31%, when compared to expenses in the second quarter of 2014.

**Lease operating cost.** These expenses decreased \$6.4 million, or 27%, compared to the level of such expenses in the second quarter of 2014. The decrease was due to lower supervision fees charged to LOE in addition to lower compression, labor and transportation costs as a result of concentrated efforts to reduce operating costs. Our lease operating costs per Boe produced were \$5.97 and \$6.83 for the three months ended June 30, 2015 and 2014, respectively.

**Transportation and gas processing.** These expenses decreased \$0.9 million, or 15% compared to the level of such expenses in the second quarter of 2014, as our production volumes decreased 17%. Our transportation and gas processing costs per Boe produced were \$1.77 and \$1.74 for the second quarters of 2015 and 2014, respectively.

**Depreciation, Depletion and Amortization (“DD&A”).** These expenses decreased \$31.0 million, or 42% from those in the second quarter of 2014. The decrease was primarily due to a lower depletable base. Our DD&A rate per Boe of production was \$14.64 and \$21.19 in the second quarters of 2015 and 2014, respectively.

**General and Administrative Expenses, Net.** These expenses decreased \$1.8 million, or 15%, from the level of such expenses in the second quarter of 2014. The decrease was primarily due to lower salaries and related benefits along with lower stock compensation and temporary labor costs, partially offset by higher professional fees, lower capitalized costs and lower supervision fee recoupments. Our net general and administrative expenses per Boe produced increased to \$3.58 per Boe in the second quarter of 2015 from \$3.50 per Boe in the second quarter of 2014.

**Severance and Other Taxes.** These expenses decreased \$5.0 million, or 53%, from second quarter of 2014 levels while oil and gas revenues decreased 57% and equivalent production volumes decreased 17%. The decrease was also driven by the reversal of prior period accruals as severance tax refunds received were higher than the original estimates. Severance and other taxes, as a percentage of oil and gas sales, were approximately 6.5% and 6.0% in the second quarters of 2015 and 2014, respectively.



Interest. Our gross interest cost in the second quarters of 2015 and 2014 was \$19.9 million, of which \$1.2 million was capitalized, respectively.

Write-down of oil and gas properties. Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, we recorded a non-cash write-down on a before-tax basis of \$260.5 million in the second quarter of 2015.

Income Taxes. Our effective income tax rate decreased to 0.2% from 42.0% for the second quarters of 2015 and 2014, respectively. The net benefit of \$0.6 million for the second quarter of 2015 was attributable to our operating loss which was almost fully offset by valuation allowances.

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## Revenues — Six Months Ended June 30, 2015 and 2014

Our oil and gas sales in the first six months of 2015 decreased by 56% compared to oil and gas sales in the first six months of 2014, primarily due to overall lower commodity pricing and lower oil and NGL production, partially offset by higher natural gas production. Average oil prices we received were 50% lower than those received during the first six months of 2014, while natural gas prices were 41% lower and NGL prices were 55% lower.

Crude oil production was 22% and 28% of our production volumes in the six months ended June 30, 2015 and 2014, respectively. Crude oil sales were 49% and 60% of oil and gas sales in the six months ended June 30, 2015 and 2014, respectively. Natural gas production was 65% and 57% of our production volumes in the six months ended June 30, 2015 and 2014, respectively. Natural gas sales were 42% and 30% of oil and gas sales in the six months ended June 30, 2015 and 2014, respectively. The remaining production and sales in each period came from NGLs.

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

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2015	2014	2015	2014
Artesia Wells	\$ 11.0	\$ 38.8	597	1,010
AWP	52.4	120.2	2,221	2,200
Fasken (1)	33.5	49.2	2,121	1,923
Other South Texas	1.9	4.6	102	132
Total South Texas	98.8	212.8	5,041	5,265
Southeast Louisiana	26.2	71.3	571	768
Central Louisiana	10.2	22.4	307	344
Other	0.4	1.0	20	17
Total	\$ 135.6	\$ 307.5	5,939	6,394

(1) Fasken amounts for the first six months of 2014 include approximately \$17.7 million (692 MBoe) representing interests sold to Saka Energi effective July 15, 2014.

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

During the first six months of 2015, our \$171.9 million, or 56% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had an approximate \$120.9 million unfavorable impact on sales due to overall lower commodity pricing; and

- Volume variances that had a \$51.0 million unfavorable impact on sales, primarily attributable to lower oil production, partially offset by higher natural gas production.



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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 six months ended June 30, 2015 and 2014:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Six Months Ended June 30, 2015	1,314	793	23.0	5,939	\$ 50.62	\$ 15.67	\$ 2.47
Six Months Ended June 30, 2014	1,821	913	22.0	6,394	\$ 100.50	\$ 35.16	\$ 4.17

For the six months ended June 30, 2015 and 2014, we recorded total net gains (losses) of \$0.3 million and (\$7.8 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 \$50.62 and \$99.27 for the six months ended June 30, 2015 and 2014, respectively, and our average natural gas price would have been \$2.48 and \$3.92 for the six months ended June 30, 2015 and 2014, respectively.

#### Costs and Expenses — Six Months Ended June 30, 2015 and 2014

Our expenses in the first six months of 2015 increased \$707.9 million, compared to those in the first six months of 2014, for the reasons noted below. Excluding the 2015 ceiling test write-down, our expenses in the first six months of 2015 decreased \$55.2 million, or 20%, when compared to expenses in the first six months of 2014.

**Lease operating cost.** These expenses decreased \$12.3 million, or 25%, compared to the level of such expenses in the first six months of 2014. The decrease was due to lower workover, labor, compression, maintenance and salt water disposal costs primarily driven by concentrated efforts to reduce operating costs. Our lease operating costs per Boe produced were \$6.09 and \$7.59 for the six months ended June 30, 2015 and 2014, respectively.

**Transportation and gas processing.** These expenses decreased \$0.9 million, or 8%, compared to the level of such expenses in the first six months of 2014, as our production volumes decreased 7%. Our transportation and gas processing costs per Boe produced were \$1.75 and \$1.77 for the six months ended June 30, 2015 and 2014, respectively.

**Depreciation, Depletion and Amortization (“DD&A”).** These expenses decreased \$33.0 million, or 24% from those in the first six months of 2014. The decrease was primarily due to a lower depletable base, partially offset by lower reserves volumes. Our DD&A rate per Boe of production was \$17.31 and \$21.23 in the six months ended June 30, 2015 and 2014, respectively.

**General and Administrative Expenses, Net.** These expenses increased \$0.3 million, or 1%, from the level of such expenses in the first six months of 2014. Our net general and administrative expenses per Boe produced increased to \$3.85 per Boe in the first six months of 2015 from \$3.53 per Boe in the first six months of 2014.

**Severance and Other Taxes.** These expenses decreased \$9.1 million, or 49%, from the first six months of 2014. The decrease was primarily driven by lower oil and gas revenues as a result of decreased commodity prices along with declining oil production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.0% and 6.1% in the six months ended June 30, 2015 and 2014, respectively.

**Interest.** Our gross interest cost in the first six months of 2015 was \$39.4 million, of which \$2.4 million was capitalized. Our gross interest cost in the first six months of 2014 was \$39.6 million, of which \$2.5 million was

capitalized. The decrease in our gross interest was due to decreased credit facility borrowings partially offset by a write-off of debt issuance costs related to our borrowing base reduction.

Write-down of oil and gas properties. Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, we recorded non-cash write-downs on a before-tax basis of \$763.1 million for the first six months of 2015.

Income Taxes. Our effective income tax rate decreased to 9.4% from 47.7% for the six months ended June 30, 2015 and 2014, respectively. The tax benefit of \$80.1 million for the first six months of 2015 was due to a reduction in our deferred tax liability resulting from the write-down of oil and gas properties, partially offset by a valuation allowance.

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Critical Accounting Policies and New Accounting Pronouncements

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

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

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

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

Principally due to the effects of pricing, and also due to the timing of projects and changes in our reserves product mix, in 2015 we reported a non-cash write-down on a before-tax basis of \$260.5 million and \$763.1 million on our oil and natural gas properties for the three and six months ended June 30, 2015, respectively.

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

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

in future periods.

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

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

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

All forward-looking statements speak only as of the date they are made. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk factors" in Item 1A of our annual report on Form 10-K for the year ended December 31, 2014. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.



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

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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 in recent periods.

Our price-risk management policy permits the utilization of agreements and financial instruments (such as futures, forward contracts, swaps and options contracts) to mitigate price risk associated with fluctuations in oil and natural gas prices. We do not utilize these agreements and financial instruments for trading and only enter into derivative agreements with banks in our credit facility. For additional discussion related to our price-risk management policy, refer to Note 7 of these condensed consolidated financial statements.

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

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

**Interest Rate Risk.** Our senior notes due in 2017, 2020 and 2022 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At June 30, 2015, we had \$272.0 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. The Company's chief executive officer and chief financial officer have evaluated such disclosure controls and procedures as of the end of the period covered by this quarterly report on Form 10-Q and have determined that such disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first six months of 2015 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

During the second quarter of 2015, there have been no material changes in our risk factors disclosed in the 2014 Annual Report Form 10-K, except for the following:

If we fail to comply with the continued listing standards of the NYSE, it may result in a delisting of our common shares from the NYSE.

Our common shares are currently and have been listed for trading on the NYSE, and the continued listing of our common shares on the NYSE is subject to our compliance with a number of listing standards. To maintain compliance with these continued listing standards, the Company is required to maintain an average closing price of \$1.00 or more over a consecutive 30 trading-day period. Beginning in mid-July 2015, the closing price of our common shares, as reported on the NYSE, has been less than \$1.00.

In addition to the above stock price criteria, the Company will be considered to be below compliance if our average global market capitalization over a consecutive 30 trading-day period is less than \$50,000,000 and, at the same time stockholders' equity is less than \$50,000,000. Beginning in mid-July 2015, our global market capitalization, as reported on the NYSE, has been less than \$50,000,000.

For each of the above compliance standards, the NYSE Listed Company Manual sets out rules and processes to cure non-compliance. For instance, upon approval from the NYSE, an issuer has 6 months to cure the listing standard related to stock price. Similarly, an issuer has 18 months to cure the listing standard related to global market capitalization.

There can be no assurance that we will be able to continue to meet the continued listing standards of the NYSE. The delisting of our common shares from the NYSE could result in even further reductions in our share price, would substantially limit the liquidity of our common shares, and materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NYSE could also have other negative results, including the potential loss of confidence by institutional investors.

Availability under our revolving credit facility depends upon a borrowing base that is subject to a scheduled redetermination by our lenders within the next 90 days. If our borrowing base is reduced, we may be required to repay amounts outstanding under our revolving credit facility.

Under the terms of our revolving credit facility, our borrowing base is subject to semi-annual redetermination by our lenders. As part of our regularly scheduled May 2015 borrowing base redetermination, and in light of the continuation of low oil and gas prices, our revolving credit facility borrowing base and commitment amounts were reduced to \$375.0 million from \$417.6 million. If we experience the continuation of low oil and gas prices, or if they decline even further, we anticipate that our existing revolving credit facility borrowing base and commitment amounts are likely to be reduced further this November as part of our next borrowing base redetermination. This reduction could result in our liquidity being severely limited and our expenditures being limited to our current cash flow. In the event the amount outstanding under our revolving credit facility at any time exceeds the borrowing base then in effect, we would be required under our revolving credit facility to repay or otherwise eliminate the amount of such excess. Our

ability to make such payment in such event cannot be assured. Failure to make such repayment could result in a default under our revolving credit facility and possibly other of our debt instruments.

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

Currently, our principal sources of liquidity are cash flow from our operations and borrowings under our revolving credit facility. As explained above, continuation of hydrocarbon prices at current levels increase the likelihood that our borrowing base will be reduced as part of our next borrowing base redetermination scheduled for this November 1st. During the first six months of 2015 we have borrowed \$75 million under our credit facility to fund a portion of our capital expenditures. If we were no longer able to draw under our credit facility, funding of our operations and drilling activities would diminish, likely reducing our cash flow from operations and slowing the development of our properties.

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

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

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
April 1 – 30, 2015 (1)	1,417	\$2.21	—	\$—
May 1 – 31, 2015 (1)	529	\$2.50	—	—
June 1 – 30, 2015 (1)	385	\$2.19	—	—
Total	2,331	\$2.27	—	\$—

(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	Amendment No. 2 to Second Amended and Restated Swift Energy Company 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 20, 2015, File No. 1-087540).
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.

Date: August 6, 2015

SWIFT ENERGY COMPANY

(Registrant)

By: /s/ Alton D. Heckaman, Jr.

Alton D. Heckaman, Jr.

Executive Vice President

Chief Financial Officer and Principal Accounting  
Officer

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Exhibit Index

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