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

FORM 10-Q

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

For the quarterly period ended September 30, 2013
Commission File Number 1-8754
SWIFT ENERGY COMPANY
(Exact Name of Registrant as Specified in Its Charter)

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

16825 Northchase Drive, Suite 400
Houston, Texas 77060
(281) 874-2700
(Address and telephone number of principal executive offices)
Securities registered pursuant to Section 12(b) of the Act:

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

Yes	þ	No	o

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

Yes	þ	No	o

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

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o

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

Yes	o	No	þ

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

Common Stock ($.01 Par Value) (Class of Stock)	43,395,684 Shares (Outstanding at October 31, 2013)

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2013
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Condensed Consolidated Balance Sheets
Swift Energy Company and Subsidiaries (in thousands, except share amounts)

	September 30, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current Assets:		
Cash and cash equivalents	$97	$170
Accounts receivable	68,814	67,318
Deferred tax asset	4,324	5,679
Other current assets	7,623	7,370
Total Current Assets	80,858	80,537
Property and Equipment:		
Property and Equipment, including $90,359 and $92,579 of unproved property costs not being amortized, respectively	5,607,100	5,192,793
Less – Accumulated depreciation, depletion, and amortization	(3,034,614)	(2,847,773)
Property and Equipment, Net	2,572,486	2,345,020
Other Long-Term Assets	17,411	18,504
Total Assets	$2,670,755	$2,444,061
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$81,608	$75,378
Accrued capital costs	58,058	73,190
Accrued interest	13,105	21,362
Undistributed oil and gas revenues	7,996	7,550
Total Current Liabilities	160,767	177,480
Long-Term Debt	1,120,402	916,934
Deferred Tax Liabilities	238,622	223,243
Asset Retirement Obligation	68,628	79,643
Other Long-Term Liabilities	10,253	9,901
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, 43,906,879 and 43,450,367 shares issued, and 43,394,911 and 42,930,071 shares outstanding, respectively	439	435
Additional paid-in capital	758,971	747,868
Treasury stock held, at cost, 511,968, and 520,296 shares, respectively	(12,556)	(13,855)
Retained earnings	325,229	302,412
Total Stockholders' Equity	1,072,083	1,036,860
Total Liabilities and Stockholders' Equity	$2,670,755	$2,444,061

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Revenues:				
Oil and gas sales	$155,049	$127,946	$442,418	$396,068
Price-risk management and other, net	(2,048)	804	(714)	3,317
Total Revenues	153,001	128,750	441,704	399,385
Costs and Expenses:				
General and administrative, net	11,146	11,952	35,062	36,025
Depreciation, depletion, and amortization	66,948	58,987	186,526	181,638
Accretion of asset retirement obligation	1,478	1,191	4,732	3,465
Lease operating cost	23,078	22,275	77,459	71,656
Transportation and gas processing	5,783	4,359	16,678	13,674
Severance and other taxes	11,695	10,680	31,971	35,840
Interest expense, net	17,495	13,762	51,297	40,546
Total Costs and Expenses	137,623	123,206	403,725	382,844
Income Before Income Taxes	15,378	5,544	37,979	16,541
Provision for Income Taxes	6,492	2,422	15,162	6,821
Net Income	$8,886	$3,122	$22,817	$9,720
Per Share Amounts-				
Basic: Net Income	$0.20	$0.07	$0.53	$0.23
Diluted: Net Income	$0.20	$0.07	$0.52	$0.23
Weighted Average Shares Outstanding - Basic	43,389	42,901	43,308	42,812
Weighted Average Shares Outstanding - Diluted	43,704	43,239	43,624	43,158

See accompanying Notes to Condensed Consolidated Financial Statements.

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Condensed Consolidated Statements of Comprehensive Income (Unaudited)
Swift Energy Company and Subsidiaries (in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net Income:	$8,886	$3,122	$22,817	$9,720
Other Comprehensive Income:				
Unrealized gains related to price risk management transactions, before taxes	—	66	—	1,237
Provision for income taxes	—	24	—	450
Unrealized gains related to price risk management transactions, net of taxes	—	42	—	787
Less: reclassification of gains on price risk management transactions to net income, before taxes	—	(244)	—	(1,415)
Provision for income taxes	—	(89)	—	(515)
Reclassification of gains on price risk management transactions to net income, net of taxes	—	(155)	—	(900)
Other comprehensive loss, before income taxes	—	(178)	—	(178)
Benefit for income taxes	—	(65)	—	(65)
Other comprehensive loss, net of taxes	—	(113)	—	(113)
Comprehensive Income	$8,886	$3,009	$22,817	$9,607

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Total
Balance, December 31, 2011	$430	$726,956	$(12,350)	$281,473	$996,509
Stock issued for benefit plans (50,987 shares)	—	354	1,300	—	1,654
Stock options exercised (63,040 shares)	1	635	—	—	636
Purchase of treasury shares (86,812 shares)	—	—	(2,805)	—	(2,805)
Tax benefits from share-based compensation	—	175	—	—	175
Employee stock purchase plan (42,624 shares)	—	1,076	—	—	1,076
Issuance of restricted stock (375,157 shares)	4	(4)	—	—	—
Amortization of share-based compensation	—	18,676	—	—	18,676
Net Income	—	—	—	20,939	20,939
Balance, December 31, 2012	$435	$747,868	$(13,855)	$302,412	$1,036,860
Stock issued for benefit plans (104,890 shares) (1)	—	(1,171)	2,793	—	1,622
Purchase of treasury shares (96,562 shares) (1)	—	—	(1,494)	—	(1,494)
Tax benefits from share-based compensation (1)	—	(1,568)	—	—	(1,568)
Employee stock purchase plan (72,273 shares) (1)	1	945	—	—	946
Issuance of restricted stock (384,239 shares) (1)	3	(3)	—	—	—
Amortization of share-based compensation (1)	—	12,900	—	—	12,900
Net Income (1)	—	—	—	22,817	22,817
Balance, September 30, 2013 (1)	$439	$758,971	$(12,556)	$325,229	$1,072,083

(1) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

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

	Nine Months Ended September 30, 2013	2012
Cash Flows from Operating Activities:		
Net income	$22,817	$9,720
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	186,526	181,638
Accretion of asset retirement obligation	4,732	3,465
Deferred income taxes	15,162	8,239
Share-based compensation expense	8,454	10,562
Other	(3,796)	(583)
Change in assets and liabilities-		
(Increase) decrease in accounts receivable	(3,696)	14,385
Increase (decrease) in accounts payable and accrued liabilities	3,873	(3,051)
Decrease in income taxes payable	(208)	(248)
Decrease in accrued interest	(8,257)	(443)
Net Cash Provided by Operating Activities	225,607	223,684
Cash Flows from Investing Activities:		
Additions to property and equipment	(435,722)	(575,711)
Proceeds from the sale of property and equipment	6,990	523
Net Cash Used in Investing Activities	(428,732)	(575,188)
Cash Flows from Financing Activities:		
Net proceeds from bank borrowings	203,600	102,640
Net proceeds from issuances of common stock	946	1,599
Purchase of treasury shares	(1,494)	(2,781)
Net Cash Provided by Financing Activities	203,052	101,458
Net decrease in Cash and Cash Equivalents	(73)	(250,046)
Cash and Cash Equivalents at Beginning of Period	170	251,696
Cash and Cash Equivalents at End of Period	$97	$1,650
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$57,990	$39,175
Cash paid during period for income taxes	$208	$248

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, 2012 as filed with the Securities and Exchange Commission.

(2) Summary of Significant Accounting Policies

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

Subsequent Events. We have evaluated subsequent events of our consolidated financial statements. There were no material subsequent events requiring additional disclosure in these financial statements.

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

- the estimated quantities of proved oil and natural gas reserves used to compute depletion of oil and natural gas properties and the related present value of estimated future net cash flows there-from,
- 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
- 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 adjustment occurs.

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 September 30, 2013 and 2012, such internal costs capitalized totaled $7.9 million and $7.8 million, respectively. For the nine months ended September 30, 2013 and 2012, such internal costs capitalized totaled $23.9 million. Interest costs are also capitalized to unproved oil and natural gas properties. For the three months ended September 30, 2013 and 2012, capitalized interest on unproved properties totaled $1.8 million and $2.0 million, respectively. For the nine months ended September 30, 2013 and 2012, capitalized interest on unproved properties totaled $5.6 million and $6.0 million, respectively. Interest not capitalized and general and administrative costs related to production and general corporate overhead are expensed as incurred.

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

(in thousands)	September 30, 2013	December 31, 2012
Property and Equipment		
Proved oil and gas properties	$5,474,748	$5,058,524
Unproved oil and gas properties	90,359	92,579
Furniture, fixtures, and other equipment	41,993	41,690
Less – Accumulated depreciation, depletion, and amortization	(3,034,614)	(2,847,773)
Property and Equipment, Net	$2,572,486	$2,345,020

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

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

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

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.

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

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

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near term. If oil and natural gas prices decline from our prices used in the Ceiling Test, it is reasonably possible that non-cash write-downs of oil and natural gas properties would occur in the future. 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.

Revenue Recognition. Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if collectability of the revenue is probable. Swift Energy uses the entitlement method of accounting in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the natural gas balancing payables are reported in "Accounts payable and accrued liabilities" on the accompanying condensed consolidated balance sheets. Natural gas balancing receivables are reported in "Other current assets" on the accompanying condensed consolidated balance sheets when our ownership share of production exceeds sales. As of September 30, 2013 and December 31, 2012, we did not have any material natural gas imbalances.

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

Accounts Receivable. We assess the collectability of accounts receivable, and based on our judgment, we accrue a reserve when we believe a receivable may not be collected. At September 30, 2013 and December 31, 2012, we had an allowance for doubtful accounts of approximately $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balance on the accompanying condensed consolidated balance sheets.

At September 30, 2013, our "Accounts receivable" balance included $52.1 million for oil and gas sales, $3.1 million for joint interest owners, $11.8 million for severance tax credit receivables and $1.8 million for other receivables. At December 31, 2012, our "Accounts receivable" balance included $53.9 million for oil and gas sales, $3.6 million for joint interest owners, $5.8 million for severance tax credit receivables and $4.0 million for other receivables.

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

The 7.125% senior notes due in 2017 mature on June 1, 2017, and the balance of their issuance costs at September 30, 2013, was $1.9 million. The 8.875% senior notes due in 2020 mature on January 15, 2020, and the balance of their issuance costs at September 30, 2013, was $3.7 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at September 30, 2013, was $6.7 million. The balance of revolving credit facility issuance costs at September 30, 2013, was $3.6 million.

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Price-Risk Management Activities. The Company follows FASB ASC 815-10, which requires that changes in the derivative’s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. The guidance also establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) is recorded in the condensed consolidated balance sheets as either an asset or a liability measured at its fair value. Hedge accounting for a qualifying hedge allows the gains and losses on derivatives to offset related results on the hedged item in the statement of operations and requires that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

Prior to January 1, 2013, the Company had elected hedge accounting on all qualifying derivative instruments. As of December 31, 2012, the Company did not have any outstanding derivatives. For all derivatives entered into after January 1, 2013, the Company elected not to apply hedge accounting. The changes in the fair value of our derivatives initiated after January 1, 2013 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 floors, calls, collars and participating collars. Prior to January 1, 2013, all hedges were designated as a hedge of the variability in cash flows associated with the forecasted sale of oil and natural gas production. Changes in the fair value of a hedge that was highly effective and was designated, documented and qualified as a cash flow hedge, to the extent that the hedge was effective, were recorded in “Accumulated other comprehensive income, net of income tax” on the accompanying condensed consolidated balance sheets. When the hedged transactions were recorded upon the actual sale of the oil and natural gas, those gains or losses were reclassified from “Accumulated other comprehensive income, net of income tax” and were recorded in “Price-risk management and other, net” on the accompanying condensed consolidated statements of operations. Changes in the fair value of derivatives that did not meet the criteria for hedge accounting, and the ineffective portion of the hedge for which hedge accounting was elected, were recognized in "Price-risk management and other, net."

During the three months ended September 30, 2013 and 2012, we recognized a net loss of $2.0 million and a net gain of $0.2 million, respectively, relating to our derivative activities. During the nine months ended September 30, 2013 and 2012, we recognized a net loss of $0.8 million and a net gain of $2.5 million, respectively, relating to our derivative activities. These amounts include an unrealized loss of $0.7 million and an unrealized gain of less than $0.1 million for the three and nine months ended September 30, 2013, respectively. Had these amounts been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. The ineffectiveness for the three and nine months ended September 30, 2012, was not material. 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 derivative assets at September 30, 2013 was $1.4 million which was recognized on the accompanying condensed consolidated balance sheet in “Other current assets.” The fair value of our derivative liabilities at September 30, 2013 was $0.6 million which was recognized on the accompanying condensed consolidated balance sheet in “Accounts payable and accrued liabilities.”

The Company uses an International Swap and Derivatives Association "ISDA" master agreement for all 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 show a net derivative fair value asset of $0.8 million at September 30, 2013. For further discussion related to the fair value of the Company's derivatives, refer to Note 7 of these condensed consolidated financial statements.

At September 30, 2013, we had $0.4 million in receivables for settled derivatives which were recognized on the accompanying balance sheet in “Accounts receivable” and were subsequently collected in October 2013. At September 30, 2013, we also had $0.4 million in payables for settled derivatives which were recognized on the accompanying balance sheet in "Accounts payable and accrued liabilities" and were subsequently paid in October 2013.

At September 30, 2013, we had natural gas collars in effect that covered natural gas production of 1,180,000 MMBtu from November 2013 through December 2013 with a floor price of $3.75 per MMBtu and a call price of $5.08 per MMBtu. In addition, we had natural gas participating collars in effect that covered natural gas production of 1,200,000 MMBtu from November 2013 through December 2013 with a floor price of $4.00 per MMBtu and call prices of $5.00 per MMBtu and $6.00 per MMBtu.

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At September 30, 2013, we had oil floors in effect that covered oil production of 252,000 barrels from October 2013 through December 2013 with a floor price of $97.00 per barrel. We also had oil calls in place that covered oil production of 282,000 barrels from October 2013 through March 2014 with call prices ranging from $110.70 to $116.60 per barrel. In addition, we had oil collars in effect that covered oil production of 477,000 barrels from October 2013 through March 2014 with a range of prices between a floor price of $90.00 per barrel and a ceiling price of $107.35 per barrel.

Supervision Fees. Consistent with industry practice, we charge a supervision fee to the wells we operate including our wells in which we own up to a 100% working interest. Supervision fees are recorded as a reduction to “General and administrative, net” on the accompanying condensed consolidated statements of operations. Our supervision fees are based on COPAS industry guidelines. The amount of supervision fees charged for the three and nine months ended September 30, 2013 and 2012 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $2.8 million and $2.9 million in the three months ended September 30, 2013 and 2012, respectively. The total amount of supervision fees charged to the wells we operated was $8.9 million and $8.6 million in the nine months ended September 30, 2013 and 2012, respectively.

Inventories. Inventories consist primarily of tubulars and other equipment and supplies that we expect to place in service in production operations. Inventories carried at cost (weighted average method) are included in “Other current assets” on the accompanying condensed consolidated balance sheets totaling $2.9 million and $5.6 million at September 30, 2013 and December 31, 2012, respectively.

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

We follow the recognition and disclosure provisions under guidance contained in FASB ASC 740-10-25. Under this guidance, tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. Our policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At September 30, 2013, we did not have any accrued liability for uncertain tax positions.

We do not believe the total of unrecognized tax positions will significantly increase or decrease during the next 12 months.

Our U.S. Federal income tax returns for 2007 forward (except for 2008 which was closed through the IRS audit process), our Louisiana income tax returns from 1998 forward, our New Zealand income tax returns after 2005, and our Texas franchise tax returns after 2007 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 state returns are significant to our financial position.

The Company is evaluating the impact of recently finalized IRS regulations concerning amounts paid to acquire, produce, or improve tangible property and recovery of basis upon disposition. At this time we do not anticipate there being a material impact.

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

	September 30, 2013	December 31, 2012

Trade accounts payable (1)	$34,497	$31,128
Accrued operating expenses	13,173	14,647
Accrued payroll costs	10,782	12,297
Asset retirement obligation – current portion	8,119	7,134
Accrued taxes	12,292	5,373
Other payables	2,745	4,799
Total accounts payable and accrued liabilities	$81,608	$75,378

(1) Included in "trade accounts payable" are liabilities of approximately $11.4 million and $13.3 million at September 30, 2013 and December 31, 2012, 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.

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Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of September 30, 2013 and December 31, 2012, these assets were approximately $1.0 million, respectively. 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. Restricted cash balances are reported in “Other Long-Term Assets” on the accompanying condensed consolidated balance sheets.

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

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

	2013
Asset Retirement Obligation recorded as of January 1	$ 86,777
Accretion expense	4,732
Liabilities incurred for new wells and facilities construction	1,550
Reductions due to sold and abandoned wells and facilities	(14,010)
Revisions in estimates	(2,302)
Asset Retirement Obligation as of September 30,	$ 76,747

Effective May 1, 2013, we sold our Brookeland field in Texas. This sale included the buyer's assumption of our plugging and abandonment liability for which we were carrying an $11.3 million asset retirement obligation related to these properties. This decrease is shown above in “Reductions due to sold and abandoned wells and facilities.”

At September 30, 2013 and December 31, 2012, approximately $8.1 million and $7.1 million of our asset retirement obligation was classified as a current liability in “Accounts payable and accrued liabilities” on the accompanying condensed consolidated balance sheets.

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of September 30, 2013.

(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 5, 2013, 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, 2012, for additional information related to these share-based compensation plans.

We follow guidance contained in FASB ASC 718 to account for share-based compensation.

We receive a tax deduction for certain stock option exercises during the period the stock options are exercised, generally for the excess of the market value on the exercise date over the exercise price of the stock option awards.

We receive an additional tax deduction when restricted stock awards vest at a higher value than the value used to recognize compensation expense at the date of grant. In accordance with guidance contained in FASB ASC 718, we are required to report excess tax benefits from the award of equity instruments as financing cash flows. For the three and nine months ended September 30, 2013 and 2012, we did not recognize any material excess tax benefit or shortfall in earnings.

There were no stock option exercises for the nine months ended September 30, 2013. Net cash proceeds from the exercise of stock options was $0.5 million for the nine months ended September 30, 2012. The actual income tax benefit from stock option exercises was $0.3 million for the nine months ended September 30, 2012.

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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 $2.2 million and $3.2 million for the three months ended September 30, 2013 and 2012, respectively, and was $7.8 million and $9.9 million for the nine months ended September 30, 2013 and 2012, respectively. Share-based compensation recorded in lease operating cost was $0.1 million for the three months ended September 30, 2013 and 2012 and was $0.2 million and $0.3 million for nine months ended September 30, 2013 and 2012, respectively. We also capitalized $1.2 million of share-based compensation for the three months ended September 30, 2013 and 2012 and capitalized $4.4 million and $4.1 million for the nine months ended September 30, 2013 and 2012, 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 with the following weighted-average assumptions for stock option awards issued during the indicated periods:

	Nine Months Ended September 30, 2012	
Dividend yield	0	%
Expected volatility	61.2	%
Risk-free interest rate	0.8	%
Expected life of stock option awards (in years)	4.3	
Weighted-average grant-date fair value	$ 15.71	

During the first nine months of 2013 we did not grant any stock option awards. The expected term for grants issued considers all relevant factors including historical and expected future employee exercise behavior. We have analyzed historical volatility and, based on an analysis of all relevant factors, we have used a 5.5 year look-back period to estimate expected volatility of our stock option grants.

At September 30, 2013, we had $0.9 million of unrecognized compensation cost related to stock option awards, which is expected to be recognized over a weighted-average period of 0.7 years. The following table represents stock option award activity for the nine months ended September 30, 2013:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,585,594	$ 33.13
Options granted	—	$ —
Options canceled	(33,226)	$ 35.39
Options exercised	—	$ —
Options outstanding, end of period	1,552,368	$ 33.08
Options exercisable, end of period	1,266,025	$ 32.59

Our stock option awards outstanding and exercisable at September 30, 2013 were out of the money and therefore had no aggregate intrinsic value. At September 30, 2013, the weighted average contract life of stock option awards outstanding was 5.4 years and the weighted average contract life of stock option awards exercisable was 4.7 years. There were no stock option exercises for the nine months ended September 30, 2013 while the total intrinsic value of stock options exercised during the nine months ended September 30, 2012 was $0.8 million.

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, 2012, allow for the issuance of restricted stock awards that generally may not be sold or otherwise

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transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2013, we had unrecognized compensation expense of $13.7 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.6 years. The grant date fair value of shares vested during the nine months ended September 30, 2013 was $12.6 million.

The following table represents restricted stock award activity for the nine months ended September 30, 2013:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	896,164	$ 33.38
Restricted shares granted	637,430	$ 15.33
Restricted shares canceled	(56,663)	$ 26.20
Restricted shares vested	(384,239)	$ 32.74
Restricted shares outstanding, end of period	1,092,692	$ 23.45

Performance-Based Restricted Stock Units

In 2013, our executive compensation program was modified and, for the first time, performance-based restricted stock units were granted containing predetermined market and performance conditions with a cliff vesting period of 3.1 years. We granted 189,700 of these units at a 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target.

The compensation expense for the market condition is based on a grant date valuation of $14.85 per unit using a Monte-Carlo simulation. The unrecognized compensation expense related to these shares is approximately $1.7 million as of September 30, 2013 and is expected to be recognized over the next 2.5 years. The performance condition is remeasured quarterly and compensation expense is recorded based on the closing market price of our stock on the date of grant ($15.47 per unit) per unit multiplied by the expected payout level. The payout level is calculated based on actual performance achieved during the performance period compared to a defined peer group. The unrecognized compensation expense related to these shares, based on the current estimated payout level achieved for the performance period, is approximately $0.3 million as of September 30, 2013 and is expected to be recognized over the next 2.5 years.

(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 EPS assumes, as of the beginning of the period, exercise of stock options and restricted stock grants using the treasury stock method. Diluted EPS also assumes conversion of performance-based restricted stock units to common shares based on the number of shares (if any) that would be issuable, according to predetermined performance and market goals, if the end of the reporting period was the end of the performance period. Certain of our stock options and restricted stock grants that would potentially dilute Basic EPS in the future were also antidilutive for the three and nine months ended September 30, 2013 and 2012, and are discussed below.

Due to recently approved amendments to our stock plan agreement which clarify that unvested shares or unvested units are not dividend eligible, our earnings per share calculations, including historical periods, have been presented based on the traditional earnings per share calculation methodology instead of the two-class methodology. The effects of this change were immaterial for all historical periods presented.

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The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and nine months ended September 30, 2013 and 2012 (in thousands, except per share amounts):

	Three Months Ended September 30, 2013			Three Months Ended September 30, 2012		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 8,886	43,389	$ 0.20	$ 3,122	42,901	$ 0.07
Dilutive Securities:						
Stock Options		—			70	
Restricted Stock Awards		288			268	
Restricted Stock Units		27			—	
Diluted EPS:						
Net Income and Assumed Share Conversions	$ 8,886	43,704	$ 0.20	$ 3,122	43,239	$ 0.07

	Nine Months Ended September 30, 2013			Nine Months Ended September 30, 2012		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:						
Net Income and Share Amounts	$ 22,817	43,308	$ 0.53	$ 9,720	42,812	$ 0.23
Dilutive Securities:						
Stock Options		—			133	
Restricted Stock Awards		249			213	
Restricted Stock Units		67			—	
Diluted EPS:						
Net Income and Assumed Share Conversions	$ 22,817	43,624	$ 0.52	$ 9,720	43,158	$ 0.23

Approximately 1.6 million and 1.4 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended September 30, 2013 and 2012, respectively, and approximately 1.6 million and 1.1 million stock options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2013 and 2012, respectively, because these stock options were antidilutive. Approximately 0.2 million and 0.4 million restricted stock awards were not included in the computation of Diluted EPS for the three months ended September 30, 2013 and 2012, respectively, and approximately 0.3 million and 0.4 million restricted stock awards were not included in the computation of Diluted EPS for the nine months ended September 30, 2013 and 2012, respectively, because they were antidilutive. Approximately 0.4 million shares related to performance-based restricted stock units that could be converted to common shares based on predetermined performance and market goals were not included in the computation of Diluted EPS for the three and nine months ended September 30, 2013, because the performance and market conditions had not been met, assuming the end of the reporting period was the end of the performance period.

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(5) Long-Term Debt

Our long-term debt as of September 30, 2013 and December 31, 2012, was as follows (in thousands):

	September 30, 2013	December 31, 2012
7.125% senior notes due in 2017	$ 250,000	$ 250,000
8.875% senior notes due in 2020 (1)	222,369	222,147
7.875% senior notes due in 2022 (1)	405,033	405,387
Bank Borrowings due in 2017	243,000	39,400
Long-Term Debt (1)	$ 1,120,402	$ 916,934

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

As of September 30, 2013, our bank borrowings of $243.0 million are due in 2017. The maturities on our senior notes are $250.0 million in 2017, $225.0 million in 2020 and $400.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of $1.8 million and $2.0 million for the three months ended September 30, 2013 and 2012, respectively, and we have capitalized interest on our unproved properties in the amount of $5.6 million and $6.0 million for the nine months ended September 30, 2013 and 2012, respectively.

Bank Borrowings. Effective October 28, 2013, our syndicate of 11 banks reaffirmed the borrowing base of $450.0 million on our $500.0 million credit facility. The commitment amount of $450.0 million and maturity date of November 1, 2017 remained unchanged.

We had $243.0 million and $39.4 million in outstanding borrowings under our credit facility at September 30, 2013 and December 31, 2012, respectively. The interest rate on our credit facility is either (a) the lead bank’s prime rate plus an applicable margin or (b) the Eurodollar rate plus an applicable margin. However with respect to (a), if the lead bank’s prime rate is not higher than each of the federal funds rate plus 0.5%, and the adjusted London Interbank Offered Rate (“LIBOR”) plus 1%, the greatest of these three rates will then apply. The applicable margins vary depending on the level of outstanding debt with escalating rates of 50 to 150 basis points above the Alternative Base Rate and escalating rates of 150 to 250 basis points for Eurodollar rate loans. At September 30, 2013, the lead bank’s prime rate was 3.25% and the commitment fee associated with the credit facility was 0.5%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to adjusted working capital ratios and EBITDAX as defined in the terms of our credit facility) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. As of September 30, 2013, we were in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and natural gas properties. Under the terms of the credit facility, the commitment amount can be less than or equal to the total amount of the borrowing base with unanimous consent of the bank group as it might change from time to time.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.6 million and $0.9 million for the three months ended September 30, 2013 and 2012, respectively. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $4.0 million and $2.1 million for the nine months ended September 30, 2013 and 2012, respectively. The amount of commitment fees included in interest expense, net was $0.2 million and $0.3 million for the three months ended September 30, 2013 and 2012, respectively, and $0.9 million and $1.1 million for the nine months ended September 30, 2013 and 2012, 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 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 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

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rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on March 1 and September 1 and commenced on March 1, 2012. On or after March 1, 2017, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter. In addition, prior to March 1, 2015, we may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 107.875% of the principal amount of the notes, plus accrued and unpaid interest. We incurred approximately $7.5 million of debt issuance costs related to these notes, which is included in “Other Long–Term Assets” on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2013.

Interest expense on the senior notes due in 2022, including amortization of debt issuance costs and debt premium, totaled $7.9 million and $5.0 million for the three months ended September 30, 2013 and 2012, respectively, and $23.7 million and $15.1 million for the nine months ended September 30, 2013 and 2012, respectively.

Senior Notes Due In 2020. These notes consist of $225.0 million of 8.875% senior notes issued at 98.389% of par, which equates to an effective yield to maturity of 9.125%. The notes were issued on November 25, 2009 with an original discount of $3.6 million and will mature on January 15, 2020. The original discount of $3.6 million is recorded in “Long-Term Debt” on our condensed consolidated balance sheets and will be amortized over the life of the notes using the effective interest method. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on January 15 and July 15 and commenced on January 15, 2010. On or after January 15, 2015, we may redeem some or all of these notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.438% of principal, declining in twelve-month intervals to 100% in 2018 and thereafter. We incurred approximately $5.0 million of debt issuance costs related to these notes, which is included in “Other Long–Term Assets” on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2013.

Interest expense on the senior notes due in 2020, including amortization of debt issuance costs and debt discount, totaled $5.2 million for the three months ended September 30, 2013 and 2012 and $15.5 million for the nine months ended September 30, 2013 and 2012.

Senior Notes Due In 2017. These notes consist of $250.0 million of 7.125% senior notes due in 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Interest on these notes is payable semi-annually on June 1 and December 1, and commenced on December 1, 2007. We may redeem some or all of these notes, with certain restrictions, starting at a redemption price of 102.375% of the principal, plus accrued and unpaid interest, declining in twelve-month intervals to 100% on June 1, 2015 and thereafter. We incurred approximately $4.2 million of debt issuance costs related to these notes, which is included in "Other Long-Term Assets" on the accompanying condensed consolidated balance sheets and will be amortized to interest expense, net over the life of the notes using the effective interest method. In the event of certain changes in control of Swift Energy, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. The terms of these notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2013.

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Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $4.6 million for the three months ended September 30, 2013 and 2012, as well as $13.7 million for the nine months ended September 30, 2013 and 2012.

(6) Acquisitions and Dispositions

Effective May 1, 2013, we disposed of our Brookeland field in Texas and received net cash proceeds of approximately $6.0 million. This disposition also included the buyer's assumption of our plugging and abandonment liability that was previously included as $11.3 million in "Asset Retirement Obligation" on the accompanying condensed consolidated balance sheets.

(7) Fair Value Measurements

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

Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and senior notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid or short-term nature of these instruments.

Based upon quoted market prices as of September 30, 2013 and December 31, 2012, the fair value and carrying value of our senior notes was as follows (in millions):

	September 30, 2013		December 31, 2012	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$256.3	$250.0	$258.1	$250.0
8.875% senior notes due in 2020	$233.7	$222.4	$244.4	$222.1
7.875% senior notes due in 2022	$400.0	$405.0	$424.0	$405.4

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

The following table presents our assets and liabilities that are measured at fair value as of September 30, 2013, and are categorized using the fair value hierarchy. For additional discussion related to the fair value of the Company's derivatives, refer to Note 2 of these condensed consolidated financial statements. At December 31, 2012, the Company did not have any derivative instruments. The fair value hierarchy has three levels based on the reliability of the inputs used to determine the fair value (in millions):

	Fair Value Measurements at			
	Total Assets (Liabilities)	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
September 30, 2013				
Assets:				
Natural Gas Derivatives	$0.7	$—	$0.7	$—

Oil Derivatives	$0.7	$—	$0.7	$—
Liabilities:				
Oil Derivatives	$(0.6)	$—	$(0.6)	$—

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

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

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

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

(8) Condensed Consolidating Financial Information

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

(9) Commitments and Contingencies

In May 2013, the Company entered into a new lease agreement for office space in Houston, Texas. In October, the Company mutually agreed with the developer to cancel the lease agreement.

We had no other material changes in our contractual commitments and obligations from the amounts referenced under Note 5 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2012.

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual reports on Form 10-K for the years ended December 31, 2012 and 2011. The following information contains forward-looking statements; see "Forward-Looking Statements" on page 29 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, and we are engaged in the exploration, development, acquisition and operation of oil and natural gas properties, with a focus on our reserves and production from our Texas properties as well as onshore and inland waters of Louisiana. We hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development and are one of the largest producers of crude oil in the state of Louisiana. Oil production accounted for 33% of our third quarter 2013 production and 70% of our oil and gas sales, and combined production of both oil and natural gas liquids ("NGLs") constituted 52% of our third quarter 2013 production and 82% of our oil and gas sales. In recent periods, this has allowed us to benefit from better margins for oil production, as oil prices are significantly higher on a Boe basis than natural gas prices.

Third Quarter 2013 Activities

- Production: Our production volumes increased by 6% in the third quarter of 2013 when compared to volumes in the same period in 2012 as oil volumes increased by 15%, NGL volumes increased by 17% and natural gas production volumes decreased by 3%. The change in volumes was primarily from our South Texas area. Sequentially, production volumes increased by 10% in the third quarter of 2013 compared to second quarter of 2013 levels as oil volumes increased by 10%, NGL volumes increased by 9% and natural gas production volumes increased by 10%. The change in volumes was primarily from our South Texas area.

- Pricing: Driven by higher prices for both oil and natural gas, our weighted average sales price in the third quarter of 2013 increased by 14% when compared to levels in the third quarter of 2012. When compared to the third quarter of 2012, oil prices increased 5%, NGL prices increased 1% and natural gas prices increased 25%. When compared to the second quarter of 2013, oil prices increased 5%, NGL prices increased 6% and natural gas prices decreased 18%.

- Cash provided by operating activities: For the first nine months of 2013, our cash provided by operating activities increased by $1.9 million or 1%, when compared to the first nine months of 2012, due primarily to higher earnings in the 2013 period, partially offset by working capital changes. In the third quarter of 2013 our cash provided by operating activities increased by $8.1 million or 12%, when compared to the second quarter of 2013, due primarily to higher revenues and earnings partially offset by working capital changes during the third quarter of 2013.

- Available liquidity: At September 30, 2013, we had $243.0 million in outstanding borrowings under our credit facility. Our borrowing base and commitment amount under the credit facility is $450.0 million, which provides us with approximately $207 million of liquidity.

- 2013 capital expenditures: Our capital expenditures on a cash flow basis were $435.7 million in the first nine months of 2013, compared to $575.7 million in the first nine months of 2012. The expenditures were mainly due to drilling and completion activity for the first nine months of 2013 in our South Texas core region as we drilled 14 wells in our Artesia Wells Eagle Ford field, 13 wells in our AWP Eagle Ford field, three wells in our AWP Olmos field and two wells in our Fasken field, which helped us evaluate and maintain our acreage positions in those areas. In Southeast Louisiana we drilled two wells at Lake Washington, one of which was a dry hole, and in Central Louisiana we drilled two non-operated wells in our Burr Ferry field and one operated well in our South Bearhead Creek field. We also drilled our first well in the Niobrara formation of La Plata County, Colorado. These expenditures were funded by $225.6 million of cash provided by operating activities and the remainder through borrowings under our credit facility.

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Strategy and Outlook

- Financial Discipline - Reduced Spending for 2014: We are taking steps to better align our capital spending with our expected cash flows in order to strengthen our balance sheet and enhance liquidity. We expect a reduction in capital spending targets for 2014 to levels more in line with our internally generated cash flow and disposition proceeds. Our priorities are financial discipline first and growth second. We expect to continue growing production and reserve volumes in South Texas, while maintaining a conservative balance sheet. We are also taking current steps to reduce our future operating and overhead costs through a number of initiatives, including reducing personnel in conjunction with any asset dispositions and alignment of our other expenses, including cancellation of a new lease for future corporate office space, which will allow us to seek out more efficient and cost effective space. Once the outcome of the sales process of our Central Louisiana assets is more certain, we will announce our estimates for 2014 capital expenditures (expected to be materially directed to our South Texas properties) along with our goals for production and reserves growth. We intend to defer completion of our 2014 budget until that time.

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

- Improved performance of Eagle Ford shale assets through reduction in per well costs: We have seen improved performance this year in our initial production rates for Eagle Ford wells, in addition to increases in two-year and five-year estimated cumulative recoveries and estimated ultimate recoveries (EUR). We have also seen our per well drilling and completion costs come down from those experienced in the prior year. Our goal for 2013 is to improve initial production rates by 10% for these wells, increase EURs by 10% and reduce the average cost per well by 10%. With faster drilling times, we are currently able to drill more wells per rig than previously expected. We have also experienced efficiency gains in our hydraulic fracturing activities (fracs), which enable us to perform more frac stages per month, lower the overall frac cost per stage and achieve better overall results. We believe that progression along this technology learning curve is important to improving performance and reducing costs. As an example, our PCQ area in McMullen County, where we have drilled more than 10 wells, has been one of our best performing areas. While no two wells are the same, we have seen significant increases in 30, 60, 90, and 120 day oil recoveries from our more recent vintage wells.

- Advances in 3D Geoscience technologies allow more targeted drilling: We are utilizing state of the art geoscience technologies to improve our lateral placements and completion design in the Eagle Ford and to better define our undeveloped resource potential in Lake Washington. In the Eagle Ford, GEOFRAC logging of the horizontal well bore has led to more effective placement of frac stages and also assisted in identifying sections of rock that are not ideal for stimulation, affording opportunities to eliminate potentially non-productive frac stages. We have been able to utilize our 3D seismic in this area, along with the analysis of cores and well logs, to identify a narrow high quality interval of the lower Eagle Ford within which to steer our laterals, resulting in marked improvement in our well results. In our Lake Washington area, we have applied new state of the art tools to better define the undeveloped resources in the field. We will be reprocessing our proprietary 3D seismic data with the help of these new tools and expect to identify additional unevaluated development potential in this field.

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

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- Divesting of our Central Louisiana assets: We have decided to divest all of our Austin Chalk and Wilcox assets in Louisiana to intensify our focus and build upon the operational success of our more predictable assets in South Texas. These Central Louisiana assets include approximately 86,000 mineral acres and three producing oil and natural gas fields: Burr Ferry, Masters Creek, and South Bearhead Creek. Although these assets have significant potential, prioritization of our future capital expenditures has led us to focus our spending and human resources in South Texas, where we believe capital can be more effectively deployed, as opposed to these longer-term assets in Central Louisiana. We have engaged Scotia Waterous (USA) Inc. to assist us in the divestiture and expect that any sale of these assets would take place during the first quarter of 2014, which should provide us with adequate capital to fund our 2014 activities in South Texas.

- Strategic Growth Initiatives: We recently drilled a well to test the Niobrara oil formation in La Plata County, Colorado, which will be completed and production tested in the fourth quarter. A decision to fracture stimulate this well will be made following the initial production testing phase. We have also explored the concept of working with potential partners on drilling a sub-salt exploration test in our Lake Washington field. A significant amount of work remains before we will be in a position to drill this latter prospect, and we would not expect to begin drilling this prospect before the end of 2014. In the second quarter of 2013, we drilled a well to test the Wilcox formation in our South Bearhead Creek field. Although this well experienced mechanical difficulties during both drilling and completion activities that will limit the well's productivity, we have proven that horizontal drilling and multi-stage completion technology will enhance development of our acreage in this formation.

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Results of Operations

Revenues — Three Months Ended September 30, 2013 and 2012

Our revenues in the third quarter of 2013 increased by 19% compared to revenues in the third quarter of 2012, due to higher oil and NGL production as well as higher natural gas and oil pricing. Average oil prices we received were 5% higher than those received during the third quarter of 2012, while natural gas prices were 25% higher, and NGL prices were 1% higher.

Crude oil production was 33% and 30% of our production volumes in the third quarters of 2013 and 2012, respectively. Crude oil sales were 70% of oil and gas sales in the third quarters of 2013 and 2012, respectively. Natural gas production was 48% and 52% of our production volumes in the third quarters of 2013 and 2012, respectively. Natural gas sales were 18% of oil and gas sales in the third quarters of 2013 and 2012, respectively. The remaining production in each period was from NGLs.

The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the three months ended September 30, 2013 and 2012:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2013	2012	2013	2012
Southeast Louisiana	$ 43.9	$ 42.8	438	464
South Texas	94.7	71.5	2,358	2,173
Central Louisiana / East Texas	15.4	13.4	247	235
Other	1.0	0.2	14	3
Total	$ 155.0	$ 127.9	3,057	2,875

In the third quarter of 2013, our $27.1 million, or 21% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $11.2 million favorable impact on sales, with an increase of $5.5 million attributable to the 25% increase in natural gas prices, an increase of $5.5 million due to the 5% increase in average oil prices received and an increase of $0.2 million due to the 1% increase in NGL prices.
- Volume variances that had a $15.9 million favorable impact on sales, with a $13.8 million increase due to a 0.1 million Bbl increase in oil production volumes and a $2.7 million increase attributable to the 0.1 million Bbl increase in NGL production volumes, partially offset by a $0.6 million decrease due to the 0.2 Bcf decrease in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the three months ended September 30, 2013 and 2012:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended September 30, 2013	1,004	600	8.7	3,057	$ 108.17	$ 31.67	$ 3.15
Three Months Ended September 30, 2012	870	512	9.0	2,875	$ 102.73	$ 31.29	$ 2.52

For the three months ended September 30, 2013 and 2012, we recorded net loss of $2.0 million and a net gain of $0.2 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net" on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $106.32 and $102.73 for the third quarters of 2013 and 2012, respectively, and our average natural gas price would have been $3.14 and $2.54 for the third quarters of 2013 and 2012, respectively.

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Costs and Expenses — Three Months Ended September 30, 2013 and 2012

Our expenses in the third quarter of 2013 increased $14.4 million, or 12%, compared to those in the third quarter of 2012, for the reasons noted below.

Lease operating cost. These costs increased $0.8 million, or 4%, compared to the level of such expenses in the third quarter of 2012. The increase was primarily related to South Texas as we incurred higher lease operator costs and higher compressor costs, partially offset by lower salt water disposal costs. Our lease operating costs per Boe produced were $7.55 and $7.75 for the third quarters of 2013 and 2012, respectively.

Transportation and gas processing. These costs increased $1.4 million, or 33%, compared to the level of such expenses in the third quarter of 2012. Our transportation and gas processing costs per Boe produced were $1.89 and $1.52 for the third quarters of 2013 and 2012, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $8.0 million, or 13% from those in the third quarter of 2012. The increase was due to higher production and a higher depletable base including higher future development costs, partially offset by higher reserve volumes. Our DD&A rate per Boe of production was $21.90 and $20.52 in the third quarters of 2013 and 2012, respectively.

General and Administrative Expenses, Net. These expenses decreased $0.8 million, or 7%, from the level of such expenses in the third quarter of 2012. The decrease was primarily due to lower deferred compensation, partially offset by lower capitalized amounts and higher temporary labor costs. For the third quarters of 2013 and 2012, our capitalized general and administrative costs totaled $7.9 million and $7.8 million, respectively. Our net general and administrative expenses per Boe produced decreased to $3.65 per Boe in the third quarter of 2013 from $4.16 per Boe in the third quarter of 2012. The supervision fees recorded as a reduction to general and administrative expenses were $2.8 million and $2.9 million for the third quarters of 2013 and 2012.

Severance and Other Taxes. These expenses increased $1.0 million, or 10%, from third quarter 2012 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.5% and 8.3% in the third quarters of 2013 and 2012, respectively. The decrease in the rate was primarily driven by a shift in oil production to South Texas, as our Texas oil production carries a lower severance rate then our Louisiana oil production.

Interest. Our gross interest cost in the third quarter of 2013 was $19.3 million, of which $1.8 million was capitalized. Our gross interest cost in the third quarter of 2012 was $15.7 million, of which $2.0 million was capitalized. The increase came from the additional $150.0 million of senior notes due 2022 that were issued in October 2012 along with additional borrowings on our credit facility.

Income Taxes. Our effective income tax rate was 42.2% and 43.7% for the third quarters of 2013 and 2012, respectively.

Revenues — Nine Months Ended September 30, 2013 and 2012

Our revenues in the first nine months of 2013 increased by 11% compared to revenues in the first nine months of 2012, due to higher natural gas pricing as well as higher oil and NGL production, partially offset by lower natural gas production and lower NGL pricing. Average oil prices we received were 1% lower than those received during the first nine months of 2012, while natural gas prices were 49% higher, and NGL prices were 17% lower.

Crude oil production was 34% and 31% of our production volumes in the nine months ended September 30, 2013 and 2012, respectively. Crude oil sales were 70% and 72% of oil and gas sales in the nine months ended September 30, 2013 and 2012, respectively. Natural gas production was 47% and 54% of our production volumes in the nine months ended September 30, 2013 and 2012, respectively. Natural gas sales were 18% and 16% of oil and gas sales in the nine months ended September 30, 2013 and 2012, respectively. The remaining production in each year was from NGLs.

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The following table provides additional information regarding our oil and gas sales, excluding any effects of our hedging activities, for the nine months ended September 30, 2013 and 2012:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2013	2012	2013	2012
Southeast Louisiana	$ 131.7	$ 157.0	1,346	1,628
South Texas	266.9	200.2	6,586	6,316
Central Louisiana / East Texas	42.0	38.3	689	636
Other	1.8	0.6	33	12
Total	$ 442.4	$ 396.1	8,654	8,592

In the nine months ended September 30, 2013, our $46.4 million, or 12% increase in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $13.5 million favorable impact on sales, with an increase of $26.5 million attributable to the 49% increase in natural gas prices, partially offset by a decrease of $10.4 million due to the 17% decrease in NGL prices and a decrease of $2.6 million due to the 1% decrease in average oil prices received.
- Volume variances that had a $32.9 million favorable impact on sales, with an $26.3 million increase attributable to the 0.2 million Bbl increase in oil production volumes and an $14.2 million increase due to the 0.4 million Bbl increase in NGL production volumes, partially offset by a $7.6 million decrease due to the 3.4 Bcf decrease in natural gas production volumes.

The following table provides additional information regarding our quarterly oil and gas sales, excluding any effects of our hedging activities, for the nine months ended September 30, 2013 and 2012:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Nine Months Ended September 30, 2013	2,903	1,705	24.3	8,654	$ 106.69	$ 30.48	$ 3.32
Nine Months Ended September 30, 2012	2,659	1,318	27.7	8,592	$ 107.61	$ 36.57	$ 2.23

For the nine months ended September 30, 2013 and 2012, we recorded a net loss of $0.8 million and a net gain of $2.5 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $105.94 and $108.46 for the nine months ended September 30, 2013 and 2012, respectively, and our average natural gas price would have been $3.38 and $2.24 for the nine months ended September 30, 2013 and 2012, respectively.

Costs and Expenses — Nine Months Ended September 30, 2013 and 2012

Our expenses for the first nine months of 2013 increased $20.9 million, or 5%, compared to those in the first nine months of 2012, for the reasons noted below.

Lease operating cost. These costs increased $5.8 million, or 8%, compared to the level of such expenses in the first nine months of 2012. Costs increased due to activities associated with a well control incident in Lake Washington during the first quarter as well as other South Texas cost increases including chemical treating costs, lease operator expenses and surface maintenance costs, partially offset by less workover expense. Our lease operating costs per Boe produced were \$8.95 and \$8.34 for the nine months ended September 30, 2013 and 2012, respectively.

Transportation and gas processing. These costs increased \$3.0 million, or 22%, compared to the level of such expenses in the first nine months of 2012. The most significant piece of the increase was due to a one-time out of period adjustment made

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in the first quarter of 2013. Our transportation and gas processing costs per Boe produced were $1.93 and $1.59 for the nine months ended September 30, 2013 and 2012, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $4.9 million, or 3% from those in the first nine months of 2012. The increase was due to a higher depletable base including higher future development costs, partially offset by higher reserve volumes. Our DD&A rate per Boe of production was $21.55 and $21.14 in the nine months ended September 30, 2013 and 2012, respectively.

General and Administrative Expenses, Net. These expenses decreased $1.0 million, or 3%, from the level of such expenses in the first nine months of 2012. The decrease was primarily due to a lower corporate benefit accrual and lower deferred compensation, partially offset by higher salaries and burdens and higher temporary labor costs. For the nine months ended September 30, 2013 and 2012, our capitalized general and administrative costs totaled $23.9 million. Our net general and administrative expenses per Boe produced decreased to $4.05 per Boe in the first nine months of 2013 from $4.19 per Boe in the first nine months of 2012. The supervision fees recorded as a reduction to general and administrative expenses were $8.9 million and $8.6 million for the nine months ended September 30, 2013 and 2012, respectively.

Severance and Other Taxes. These expenses decreased $3.9 million, or 11%, from first nine months of 2012 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 7.2% and 9.0% in the nine months ended September 30, 2013 and 2012, respectively. The decrease in the rate was primarily driven by a shift in oil production to South Texas, as our Texas oil production carries a lower severance rate then our Louisiana oil production.

Interest. Our gross interest cost in the first nine months of 2013 was $56.9 million, of which $5.6 million was capitalized. Our gross interest cost in the first nine months of 2012 was $46.5 million, of which $6.0 million was capitalized. The increase came from the additional $150.0 million of senior notes due 2022 that were issued in October 2012 along with additional borrowings on our credit facility.

Income Taxes. Our effective income tax rate was 39.9% and 41.2% for the nine months ended September 30, 2013 and 2012, respectively.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the first nine months of 2013, our net cash provided by operating activities was $225.6 million, representing a 1% increase compared to $223.7 million generated during the same period of 2012. The increase was mainly due to changes in working capital.

Working Capital and Debt to Capitalization Ratio. Our working capital increased from a deficit of $96.9 million at December 31, 2012, to a deficit of $79.9 million at September 30, 2013. Working capital, which is calculated as current assets less current liabilities, can be used to measure both a company's operational efficiency and short-term financial health. The Company uses this measure to track our short-term financial position. Our working capital ratio does not include available liquidity through our credit facility. Our debt to capitalization ratio was 51% and 47% at September 30, 2013 and December 31, 2012, respectively.

Existing Credit Facility. Our borrowing base was reaffirmed at $450.0 million as of October 28, 2013. The commitment amount and maturity of the credit facility remained unchanged.

At September 30, 2013, we had $243.0 million in outstanding borrowings under our credit facility. Our available borrowings under our credit facility provide us liquidity along with any proceeds received from asset sales. In light of credit market volatility in recent years, which caused many financial institutions to experience liquidity issues, we periodically review the creditworthiness of the banks that fund our credit facility.

Contractual Commitments and Obligations

In May 2013, the Company entered into a new lease agreement for office space in Houston, Texas. In October, the Company mutually agreed with the developer to cancel the lease agreement.

We had no other material changes in our contractual commitments and obligations from December 31, 2012 amounts referenced under “Contractual Commitments and Obligations” in Management's Discussion and Analysis in our Annual Report on Form 10-K for the period ending December 31, 2012.

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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 property-by-property based on current economic conditions and are amortized to expense as our capitalized oil and natural gas property costs are amortized. We compute the provision for depreciation, depletion, and amortization ("DD&A") of oil and natural gas properties using the unit-of-production method.

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

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

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

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

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

New Accounting Pronouncements. There are no material new accounting pronouncements that have been issued but not yet adopted as of September 30, 2013.

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Forward-Looking Statements

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

Forward-looking statements may include statements about our:

• business strategy;
• reserves;
• technology;
• cash flows and liquidity;
• financial strategy, budget, projections and operating results;
• oil and natural gas pricing expectations;
• timing and amount of future production of oil and natural gas;
• availability of drilling and production equipment;
• availability of oil field labor;
• the amount, nature and timing of capital expenditures, including future development costs;
• availability and terms of capital;
• drilling of wells;
• marketing and transportation of oil and natural gas;
• exploitation or property acquisitions;
• costs of exploiting and developing our properties and conducting other operations;
• general economic conditions;
• opportunities to monetize assets;
• competition in the oil and natural gas industry;
• 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;
• estimated future net reserves and present value thereof; and
• 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, 2012. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. This commodity pricing volatility has continued with unpredictable price swings throughout 2012 and 2013.

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.

Price Risk – At September 30, 2013, we had natural gas collars in effect that covered natural gas production of 1,180,000 MMBtu from November 2013 through December 2013 and natural gas participating collars in effect that covered natural gas production of 1,200,000 MMBtu from November 2013 through December 2013. In addition we had had oil floors in effect that covered oil production of 252,000 barrels from October 2013 through December 2013, oil calls in effect that covered oil production of 282,000 barrels from October 2013 through March 2014 and oil collars in effect that covered oil production of 477,000 barrels from October 2013 through March 2014.

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

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

Interest Rate Risk. Our senior notes due in 2017, 2020 and 2022 have fixed interest rates, so consequently we are not exposed to cash flow risk from market interest rate changes on these notes. At September 30, 2013, we had $243.0 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 nine months of 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

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PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

There have been no material changes in our risk factors from those disclosed in our 2012 Annual Report on Form 10-K.

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

The following table summarizes repurchases of our common stock occurring during the third quarter of 2013:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in thousands)
07/01/13 – 07/31/13 (1)	123	$12.01	—	$—
08/01/13 – 08/31/13 (1)	4,640	$11.89	—	—
09/01/13 – 09/30/13 (1)	369	$11.35	—	—
Total	5,132	$11.85	—	$—

(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.

31.1*	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32*	Certification of Chief Executive Officer and Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document

101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

*Filed herewith

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SIGNATURES

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

		SWIFT ENERGY COMPANY (Registrant)
Date:	October 31, 2013	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date:	October 31, 2013	By: /s/ Barry S. Turcotte Barry S. Turcotte Vice President, Controller and Principal Accounting Officer

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Exhibit Index

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