SWIFT ENERGY CO
Form 10-Q
November 01, 2012

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, 2012
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)	42,923,371 Shares (Outstanding at October 31, 2012)

1

SWIFT ENERGY COMPANY

FORM 10-Q

FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2012
INDEX

Table of Contents

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

	September 30, 2012 (Unaudited)	December 31, 2011
ASSETS		
Current Assets:		
Cash and cash equivalents	$1,650	$251,696
Accounts receivable	49,994	64,392
Deferred tax asset	4,864	6,603
Other current assets	5,873	5,460
Total Current Assets	62,381	328,151
Property and Equipment:		
Property and Equipment	5,046,268	4,466,845
Less – Accumulated depreciation, depletion, and amortization	(2,781,965)	(2,599,079)
Property and Equipment, Net	2,264,303	1,867,766
Other Long-Term Assets	14,803	16,552
Total Assets	$2,341,487	$2,212,469
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$99,606	$95,966
Accrued capital costs	82,187	98,844
Accrued interest	12,016	12,459
Undistributed oil and gas revenues	2,722	4,525
Total Current Liabilities	196,531	211,794
Long-Term Debt	822,721	719,775
Deferred Tax Liabilities	212,876	206,567
Asset Retirement Obligation	77,204	67,115
Other Long-Term Liabilities	10,795	10,709
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, 43,431,240 and 42,969,546 shares issued, and 42,912,453 and 42,485,075 shares outstanding, respectively	434	430
Additional paid-in capital	743,677	726,956
Treasury stock held, at cost, 518,787, and 484,471 shares, respectively	(13,831)	(12,350)
Retained earnings	291,193	281,473
Accumulated other comprehensive loss, net of income tax	(113)	—
Total Stockholders' Equity	1,021,360	996,509
Total Liabilities and Stockholders' Equity	$2,341,487	$2,212,469

See accompanying Notes to Condensed Consolidated Financial Statements.

3

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Revenues:				
Oil and gas sales	$127,946	$143,123	$396,068	$446,537
Price-risk management and other, net	804	(591)	3,317	(2,499)
Total Revenues	128,750	142,532	399,385	444,038
Costs and Expenses:				
General and administrative, net	11,952	11,378	36,025	32,687
Depreciation, depletion, and amortization	58,987	54,404	181,638	163,141
Accretion of asset retirement obligation	1,191	1,183	3,465	3,482
Lease operating cost	26,634	26,206	85,330	78,296
Severance and other taxes	10,680	13,527	35,840	39,223
Interest expense, net	13,762	8,439	40,546	25,449
Total Costs and Expenses	123,206	115,137	382,844	342,278
Income from Continuing Operations Before Income Taxes	5,544	27,395	16,541	101,760
Provision for Income Taxes	2,422	10,388	6,821	37,822
Income from Continuing Operations	3,122	17,007	9,720	63,938
Income (loss) from Discontinued Operations, net of taxes	—	(31)	—	14,247
Net Income	$3,122	$16,976	$9,720	$78,185
Per Share Amounts-				
Basic: Income from Continuing Operations	$0.07	$0.39	$0.22	$1.48
Income (loss) from Discontinued Operations, net of taxes	—	——	—	0.33
Net Income	$0.07	$0.39	$0.22	$1.81
Diluted: Income from Continuing Operations	$0.07	$0.39	$0.22	$1.47
Income (loss) from Discontinued Operations, net of taxes	—	—	—	0.33
Net Income	$0.07	$0.39	$0.22	$1.80
Weighted Average Shares Outstanding - Basic	42,901	42,470	42,812	42,365

See accompanying Notes to Condensed Consolidated Financial Statements.

4

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net Income:	$3,122	$16,976	$9,720	$78,185
Other Comprehensive Income:				
Unrealized gains (losses) related to price risk management transactions, before taxes	66	(72)	1,237	(405)
Provision (benefit) for income taxes	24	(27)	450	(148)
Unrealized gains (losses) related to price risk management transactions, net of taxes	42	(45)	787	(257)
Less: reclassification of (gains) losses on price risk management transactions to net income, before taxes	(244)	(260)	(1,415)	623
(Provision) benefit for income taxes	(89)	(95)	(515)	229
Reclassification of (gains) losses on price risk management transactions to net income, net of taxes	(155)	(165)	(900)	394
Other comprehensive income (loss), before income taxes	(178)	(332)	(178)	218
Provision (benefit) for income taxes	(65)	(122)	(65)	80
Other comprehensive income (loss), net of taxes	(113)	(210)	(113)	138
Comprehensive Income	$3,009	$16,766	$9,607	$78,323

See accompanying Notes to Condensed Consolidated Financial Statements.

Table of Contents

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

	Common Stock	Additional Paid-in Capital	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2010	$424	$706,857	$(9,778)	$182,652	$(138)	$880,017
Stock issued for benefit plans (37,068 shares)	—	791	821	—	—	1,612
Stock options exercised (130,902 shares)	1	1,150	—	—	—	1,151
Purchase of treasury shares (80,014 shares)	—	—	(3,393)	—	—	(3,393)
Tax benefits from stock compensation	—	333	—	—	—	333
Employee stock purchase plan (49,089 shares)	1	999	—	—	—	1,000
Issuance of restricted stock (348,972 shares)	4	(4)	—	—	—	—
Amortization of stock compensation	—	16,830	—	—	—	16,830
Net Income	—	—	—	98,821	—	98,821
Other comprehensive income	—	—	—	—	138	138
Balance, December 31, 2011	$430	$726,956	$(12,350)	$281,473	$—	$996,509
Stock issued for benefit plans (50,987 shares) (1)	—	354	1,300	—	—	1,654
Stock options exercised (49,605 shares) (1)	—	523	—	—	—	523
Purchase of treasury shares (85,302 shares) (1)	—	—	(2,781)	—	—	(2,781)
Tax benefits from stock compensation (1)	—	126	—	—	—	126
Employee stock purchase plan (42,624 shares) (1)	—	1,076	—	—	—	1,076
Issuance of restricted stock (369,465 shares) (1)	4	(4)	—	—	—	—
Amortization of share-based compensation (1)	—	14,646	—	—	—	14,646
Net Income (1)	—	—	—	9,720	—	9,720
Other comprehensive loss (1)	—	—	—	—	(113)	(113)
Balance, September 30, 2012 (1)	$434	$743,677	$(13,831)	$291,193	$(113)	$1,021,360

(1) Unaudited

See accompanying Notes to Condensed Consolidated Financial Statements.

6

Table of Contents

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

	Nine Months Ended September 30,	
	2012	2011
Cash Flows from Operating Activities:		
Net income	$9,720	$78,185
Less gain from discontinued operations, net of taxes	—	(14,247)
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	181,638	163,141
Accretion of asset retirement obligation	3,465	3,482
Deferred income taxes	8,239	36,332
Stock-based compensation expense	10,562	9,281
Other	(583)	(1,410)
Change in assets and liabilities-		
Decrease in accounts receivable	14,385	6,694
Increase (decrease) in accounts payable and accrued liabilities	(3,051)	8,077
Decrease in income taxes payable	(248)	(234)
Decrease in accrued interest	(443)	(787)
Cash provided by operating activities – continuing operations	223,684	288,514
Cash provided by operating activities – discontinued operations	—	5
Net Cash Provided by Operating Activities	223,684	288,519
Cash Flows from Investing Activities:		
Additions to property and equipment	(575,711)	(368,754)
Proceeds from the sale of property and equipment	523	6,084
Cash used in investing activities – continuing operations	(575,188)	(362,670)
Cash provided by investing activities – discontinued operations	—	5,000
Net Cash Used in Investing Activities	(575,188)	(357,670)
Cash Flows from Financing Activities:		
Net proceeds from bank borrowings	102,640	—
Net proceeds from issuances of common stock	1,599	2,102
Purchase of treasury shares	(2,781)	(3,319)
Cash provided by (used in) financing activities – continuing operations	101,458	(1,217)
Cash provided by financing activities – discontinued operations	—	—
Net Cash Provided By (Used in) Financing Activities	101,458	(1,217)
Net Decrease in Cash and Cash Equivalents	(250,046)	(70,368)
Cash and Cash Equivalents at Beginning of Period	251,696	86,367
Cash and Cash Equivalents at End of Period	$1,650	$15,999
Supplemental Disclosures of Cash Flows Information:		
Cash paid during period for interest, net of amounts capitalized	$39,175	$24,693
Cash paid during period for income taxes	$248	$1,770

See accompanying Notes to Condensed Consolidated Financial Statements.

Table of Contents

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries

(1) General Information

The condensed consolidated financial statements included herein have been prepared by Swift Energy Company ("Swift Energy," the "Company," or "we") and reflect necessary adjustments, all of which were of a recurring nature unless otherwise disclosed herein, and are in the opinion of our management necessary for a fair presentation. Certain information and footnote 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, 2011 as filed with the Securities and Exchange Commission. The accompanying condensed consolidated financial statements, for the nine months ended September 30, 2012, include a reduction of approximately $0.9 million to oil and gas revenue and approximately $0.8 million of additional severance tax expense. Both of these items related to prior year activity and were not deemed material with respect to either the results of the prior year or the anticipated results and the trend of earnings for fiscal year 2012.

(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.

Discontinued Operations. Unless otherwise indicated, information presented in the notes to the condensed consolidated financial statements relates only to Swift Energy's continuing operations. Information related to discontinued operations is included in Note 6 and in some instances, where appropriate, is included as a separate disclosure within the individual footnotes.

Subsequent Events. In the fourth quarter of 2012, we issued an additional $150.0 million of 7.875% senior notes due on March 1, 2022 and used the proceeds to pay down the outstanding borrowings under our credit facility. We also extended the maturity on our credit facility through November 1, 2017 and increased the borrowing base and commitment amount. See footnote 5 for further details of these subsequent events.

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, and
- estimates in the calculation of the fair value of hedging assets.

Table of Contents

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.

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 nine months ended September 30, 2012 and 2011, such internal costs capitalized totaled $23.9 million and $21.9 million, respectively. Interest costs are also capitalized to unproved oil and natural gas properties. For the nine months ended September 30, 2012 and 2011, capitalized interest on unproved properties totaled $6.0 million and $5.7 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, 2012	December 31, 2011
Property and Equipment		
Proved oil and gas properties	$4,913,556	$4,343,867
Unproved oil and gas properties	91,415	84,146
Furniture, fixtures, and other equipment	41,297	38,832
Less – Accumulated depreciation, depletion, and amortization	(2,781,965)	(2,599,079)
Property and Equipment, Net	$2,264,303	$1,867,766

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 2 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.

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 and the effects of hedging, 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 calculation of the Ceiling Test and provision for DD&A is 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 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.

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, 2012 and December 31, 2011, 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, 2012 and December 31, 2011, 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, 2012, our "Accounts receivable" balance included $39.5 million for oil and gas sales, $3.5 million for joint interest owners and $7.0 million for other receivables. At December 31, 2011, our "Accounts receivable" balance included $54.7 million for oil and gas sales, $4.2 million for joint interest owners and $5.6 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 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, 2012, was $2.3 million, net of accumulated amortization of $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, 2012, was $4.1 million, net of accumulated amortization of $1.0 million. The 7.875% senior notes due in 2022 mature on March 1, 2022, and the balance of their issuance costs at September 30, 2012, was $4.5 million, net of accumulated amortization of $0.3 million. The balance of revolving credit facility issuance costs at September 30, 2012, was $2.9 million, net of accumulated amortization of $4.6 million.

Table of Contents

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. Changes in the fair value of derivatives that do not meet the criteria for hedge accounting, and the ineffective portion of the hedge, are recognized currently in income.

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 and collars. When we entered into the transactions discussed below, they 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 is highly effective and is designated and documented and qualifies as a cash flow hedge, to the extent that the hedge is effective, are recorded in "Accumulated other comprehensive income, net of income tax." When the hedged transactions are recorded upon the actual sale of the oil and natural gas, these gains or losses are reclassified from "Accumulated other comprehensive income, net of income tax" on the accompanying condensed consolidated balance sheets and are recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. The fair values of our derivatives are computed using the Black-Scholes-Merton option pricing model and are periodically verified against quotes from brokers.

During the three months ended September 30, 2012 and 2011, we recognized a net gain of $0.2 million and $0.3 million, respectively, relating to our derivative activities. During the nine months ended September 30, 2012 and 2011, we recognized a net gain of $2.5 million and a net loss of $0.8 million, respectively, relating to our derivative activities. This activity is recorded in "Price-risk management and other, net" on the accompanying condensed consolidated statements of operations. Had these amounts been recognized in the oil and gas sales account they would not have materially changed our per unit sales prices received. The ineffectiveness reported in "Price-risk management and other, net" for the three and nine month periods ended September 30, 2012 and 2011, was not material.

At September 30, 2012, the Company had $0.1 million of derivative losses recorded in "Accumulated other comprehensive income, net of income tax" on the accompanying condensed consolidated balance sheet. At December 31, 2011, the Company had no derivative gains or losses recorded. At September 30, 2012, the Company did not have any significant fair value recorded for derivative instruments while at December 31, 2011, we recognized $0.1 million of fair value on the accompanying condensed consolidated balance sheet in "Other current assets."

At September 30, 2012, we had natural gas price floors in effect that cover natural gas production of 1,660,000 MMBtu from October 2012 through November 2012 with strike prices ranging from of $2.92 per MMBtu to $2.97 per MMBtu.

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." Our supervision fees are based on COPAS guidelines. The amount of supervision fees charged for the first nine months of 2012 and 2011 did not exceed our actual costs incurred. The total amount of supervision fees charged to the wells we operated was $8.6 million and $10.0 million in the first nine months of 2012 and 2011, 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 $2.7 million at September 30, 2012 and $3.6 million at December 31, 2011.

In the nine months ended September 30, 2012 and 2011, we recorded a charge of less than $0.1 million and $1.6 million, respectively, related to inventory obsolescence in “Price-risk management and other, net” on the accompanying condensed statement of operations.

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.

Table of Contents

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. The Company's deferred tax liability for uncertain tax positions of $1.0 million is included in "Other Long-Term Liabilities" on the accompanying condensed consolidated balance sheets. If recognized, these tax benefits would fully impact our effective tax rate. This benefit is likely to be recognized within the next 12 months due to the lapse of the applicable statute of limitations.

Our policy is to record interest and penalties relating to income taxes in income tax expense. As of September 30, 2012, we did not have any amount accrued for interest and penalties on uncertain tax positions.

Our U.S. Federal income tax returns for 2002 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 2006 remain subject to examination by the taxing authorities. There are no material unresolved items related to income tax returns previously audited by these taxing authorities. No other state income tax returns are significant to our financial position.

Accounts Payable and Accrued Liabilities. The “Accounts payable and accrued liabilities” balances on the accompanying condensed consolidated balance sheets are summarized below for presentation purposes. The following is a detailed breakout of certain items within “Accounts payable and accrued liabilities” in the corresponding periods (in thousands):

	September 30, 2012	December 31, 2011
Trade accounts payable (1)	$60,785	$42,080
Accrued operating expenses	11,328	15,833
Accrued payroll costs	10,984	14,345
Asset retirement obligation – current portion	6,088	9,279
Accrued taxes	8,618	7,604
Other payables	1,803	6,825
Total accounts payable and accrued liabilities	$99,606	$95,966

(1) Included in “trade accounts payable” are liabilities of approximately $28.3 million and $18.7 million at September 30, 2012 and December 31, 2011, 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.

Restricted Cash. These balances primarily include amounts held in escrow accounts to satisfy domestic plugging and abandonment obligations. As of September 30, 2012 and December 31, 2011, these assets were approximately $1.0 million and $1.3 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.

Accumulated Other Comprehensive Loss, Net of Income Tax. We follow the guidance contained in FASB ASC 220-10, which establishes standards for reporting comprehensive income. In addition to net income, comprehensive income or loss includes all changes to equity during a period, except those resulting from investments and distributions to the owners of the Company. At September 30, 2012, the Company had $0.1 million in losses recorded in “Accumulated other comprehensive income, net of income tax” on the accompanying condensed consolidated balance sheet. The components of accumulated other comprehensive income and related tax effects for 2012 were as follows (in thousands):

	Gross Value	Tax Effect	Net of Tax Value
Other comprehensive loss at December 31, 2011	$—	$—	$—
Change in fair value of cash flow hedges	1,237	450	787
Effect of cash flow hedges settled during the period	(1,415)	(515)	(900)
Other comprehensive loss at September 30, 2012	$(178)	$(65)	$(113)

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 over the estimated oil and natural gas reserves of the related asset. Upon settlement of the liability, an entity 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):

	2012
Asset Retirement Obligation recorded as of January 1	$ 76,393
Accretion expense	3,465
Liabilities incurred for new wells and facilities construction	1,148
Reductions due to abandoned wells	(1,692)
Revisions in estimates	3,978
Asset Retirement Obligation as of September 30	$ 83,292

At September 30, 2012, approximately $6.1 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. In June 2011, the FASB issued ASU No. 2011-5, which changes the required presentation of other comprehensive income. Under the new guidance, entities will be required to present net income and other comprehensive income, along with the components of net income and other comprehensive income, in either one continuous statement of comprehensive income or in two separate but consecutive statements of net income and comprehensive income. The accounting standards update eliminates the option of presenting the components of other comprehensive income within the statement of changes in stockholders' equity. We adopted this guidance for the period ending March 31, 2012, which can be seen in our Condensed Consolidated Statements of Comprehensive Income.

(3) Share-Based Compensation

We have various types of share-based compensation plans. Refer to Note 6 of our consolidated financial statements in our Annual Report on Form 10-K for the fiscal year ended December 31, 2011, 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 options are exercised, generally for the excess of the market value on the exercise date over the exercise price of the options. We receive an additional tax deduction when restricted stock vests 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 nine months ended September 30, 2012 and 2011, we did not recognize any excess tax benefit or shortfall.

Net cash proceeds from the exercise of stock options were $0.5 million and $1.1 million for the nine months ended September 30, 2012 and 2011, respectively. The actual income tax benefit from stock option exercises was $0.3

million and $1.1 million for the nine months ended September 30, 2012 and 2011, respectively.

Share-based compensation expense for both stock options and restricted stock issued to both employees and non-employees, which was recorded in “General and administrative, net” in the accompanying condensed consolidated statements of operations, was $3.2 million for the three months ended September 30, 2012 and 2011, respectively and was $9.9 million and $8.8 million for the nine months ended September 30, 2012 and 2011, respectively. Share-based compensation recorded in lease operating cost was $0.1 million for the three months ended September 30, 2012 and 2011 and was $0.3 million and $0.2 million for the nine months ended September 30, 2012 and 2011. We also capitalized $1.2 million and $1.1 million of share-based compensation for the three months ended September 30, 2012 and 2011, respectively and capitalized $4.1 million and $3.1 million of share-based

Table of Contents

compensation for the nine months ended September 30, 2012 and 2011, respectively. We view all awards of stock compensation as a single award with an expected life equal to the average expected life of component awards and amortize the award on a straight-line basis over the life of the award.

Stock Options

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 options issued during the indicated periods:

	Nine Months Ended September 30,	
	2012	2011
Dividend yield	0%	0%
Expected volatility	61.2%	58.8%
Risk-free interest rate	0.8%	1.9%
Expected life of options (in years)	4.3	3.8
Weighted-average grant-date fair value	$15.71	$19.17

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 2012 and 2011 stock option grants.

At September 30, 2012, we had $4.2 million of unrecognized compensation cost related to stock options, which is expected to be recognized over a weighted-average period of 1.0 year. The following table represents stock option activity for the nine months ended September 30, 2012:

	Shares	Wtd. Avg. Exercise Price
Options outstanding, beginning of period	1,375,281	$ 32.46
Options granted	336,092	$ 32.39
Options canceled	(32,610)	$ 41.19
Options exercised	(70,297)	$ 15.92
Options outstanding, end of period	1,608,466	$ 32.97
Options exercisable, end of period	1,013,829	$ 32.16

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at September 30, 2012 was $1.7 million and 6.1 years and $1.7 million and 4.8 years, respectively. The total intrinsic value of options exercised during the nine months ended September 30, 2012 was $0.8 million.

Restricted Stock

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, 2011, allow for the issuance of restricted stock awards that may not be sold or otherwise transferred until certain restrictions have lapsed. The unrecognized compensation cost related to these awards is expected to be expensed over the period the restrictions lapse (generally one to three years).

The compensation expense for these awards was determined based on the closing market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of September 30, 2012, we had unrecognized compensation expense of $19.2 million related to restricted stock awards which is expected to be recognized over a weighted-average period of 1.2 years. The grant date fair value of shares vested during the nine months ended September 30, 2012 was $9.8 million.

Table of Contents

The following table represents restricted stock activity for the nine months ended September 30, 2012:

	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	834,703	$31.89
Restricted shares granted	529,050	$31.50
Restricted shares canceled	(67,943)	$33.73
Restricted shares vested	(369,465)	$26.48
Restricted shares outstanding, end of period	926,345	$33.69

(4) Earnings Per Share

The Company computes earnings per share in accordance with FASB ASC 260-10. Under the guidance, unvested restricted stock grants that contain non-forfeitable rights to dividends or dividend equivalents are participating securities and, therefore, are included in computing basic earnings per share (EPS) pursuant to the two-class method. The two-class method determines earnings per share for each class of common stock and participating securities according to dividends or dividend equivalents and their respective participation rights in undistributed earnings.

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during each period. Diluted EPS for the three and nine month periods ended September 30, 2012 and 2011 assumes, as of the beginning of the period, exercise of stock options using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the three and nine month periods ended September 30, 2012 and 2011, and are discussed below.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the three and nine month periods ended September 30, 2012 and 2011 (in thousands, except per share amounts):

	Three Months Ended September 30, 2012			Three Months Ended September 30, 2011		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income from continuing operations, and Share Amounts	$3,122	42,901		$17,007	42,470	
Less: (Income) loss from continuing operations allocated to unvested shares	(68)	—		(326)	—	
Income from continuing operations allocated to common shares	$3,054	42,901	$0.07	$16,681	42,470	$0.39
Dilutive Securities:						
Plus: Income from continuing operations allocated to unvested shares	68	—		326	—	
Less: (Income) loss from continuing operations re-allocated to unvested shares	(68)	—		(324)	—	
Stock Options	—	70		—	208	
Diluted EPS:						
Income from continuing operations allocated to common shares, and assumed share conversions	$3,054	42,971	$0.07	$16,683	42,678	$0.39

15

Table of Contents

	Nine Months Ended September 30, 2012			Nine Months Ended September 30, 2011		
	Income from Continuing Operations	Shares	Per Share Amount	Income from Continuing Operations	Shares	Per Share Amount
Basic EPS:						
Income from continuing operations, and Share Amounts	$9,720	42,812		$63,938	42,365	
Less: (Income) loss from continuing operations allocated to unvested shares	(210)	—		(1,195)	—	
Income from continuing operations allocated to common shares	$9,510	42,812	$0.22	$62,743	42,365	$1.48
Dilutive Securities:						
Plus: Income from continuing operations allocated to unvested shares	210	—		1,195	—	
Less: (Income) loss from continuing operations re-allocated to unvested shares	(209)	—		(1,188)	—	
Stock Options	—	133		—	254	
Diluted EPS:						
Income from continuing operations allocated to common shares, and assumed share conversions	$9,511	42,945	$0.22	$62,750	42,619	$1.47

Options to purchase approximately 1.6 million shares at an average exercise price of $32.97 were outstanding at September 30, 2012, while options to purchase approximately 1.4 million shares at an average exercise price of $32.44 were outstanding at September 30, 2011. Approximately 1.4 million and 0.8 million stock options to purchase shares were not included in the computation of Diluted EPS for the three months ended September 30, 2012 and 2011, respectively, and approximately 1.1 million and 0.7 million stock options to purchase shares were not included in the computation of Diluted EPS for the nine months ended September 30, 2012 and 2011 because these stock options were antidilutive, in that the sum of the stock option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods.

(5) Long-Term Debt

Our long-term debt as of September 30, 2012 and December 31, 2011, was as follows (in thousands):

	September 30, 2012	December 31, 2011
7.125% senior notes due in 2017	$250,000	$250,000
8.875% senior notes due in 2020 (1)	222,076	221,873
7.875% senior notes due in 2022 (1)	248,005	247,902
Bank Borrowings	102,640	—
Long-Term Debt (1)	$822,721	$719,775

(1) Amounts are shown net of debt discount

As of September 30, 2012, the maturities on our long-term debt were $102.6 million in 2015, $250.0 million in 2017, $225.0 million in 2020 and $250.0 million in 2022.

We have capitalized interest on our unproved properties in the amount of $2.0 million for the three months ended September 30, 2012 and 2011, respectively and we have capitalized interest on our unproved properties in the amount of $6.0 million and $5.7 million for the nine months ended September 30, 2012 and 2011, respectively.

16

Table of Contents

Bank Borrowings. On October 31, 2012, we renewed and extended the maturity of our $500.0 million credit facility with a syndicate of 11 banks through November 1, 2017 from May 12, 2016. We also increased the borrowing base and commitment amount to $450.0 million from a previous borrowing base and commitment amount of $375.0 million and $300.0 million, respectively, at September 30, 2012.

At September 30, 2012, we had $102.6 million in outstanding borrowings under our credit facility while at December 31, 2011, we did not have any borrowings under our credit facility. The interest rate on our credit facility is either (a) the lead bank's prime 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, 2012, the lead bank's prime rate was 3.25% and the commitment fee associated with the unfunded portion of the borrowing base was set at 50 basis points. On October 31, 2012, the commitment fee associated with the first $225.0 million unfunded portion of the borrowing base was set at 37.5 basis points while the commitment fee on any remaining unfunded portion was set at 50 basis points.

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) and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. As of September 30, 2012, 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, we can increase the commitment amount 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 $0.9 million and $0.6 million for the three months ended September 30, 2012 and 2011, respectively. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $2.1 million and $1.8 million for the nine months ended September 30, 2012 and 2011, respectively. The amount of commitment fees included in interest expense, net was $0.3 million and $0.4 million for the three months ended September 30, 2012 and 2011, respectively. The amount of commitment fees included in interest expense, net was $1.1 million for the nine months ended September 30, 2012 and 2011.

Senior Notes Due In 2022. At September 30, 2012, These notes consisted of $250.0 million of 7.875% senior notes issued at 99.156% of par, which equates to an effective yield to maturity of 8%. These notes were issued on November 30, 2011 with an original discount of $2.1 million and will mature on March 1, 2022. The original discount of $2.1 million is recorded in "Long-Term Debt" on our condensed consolidated balance sheets and will be amortized over the life of the notes. 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. Payment of 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 $4.8 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, a limitation on how much of our own common stock we may repurchase. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2012. Under the terms of the sale of these senior notes due in 2022, Swift was required to offer to exchange these notes for registered notes with the same terms. In April 2012 we commenced the exchange offer for all of these senior notes due in 2022, and completed the exchange in May 2012.

On October 3, 2012, we issued an additional $150.0 million of 7.875% senior notes due on March 1, 2022. The notes were issued at 105% of par, which equates to a yield to worst of 6.993%. The premium of $7.5 million will be recorded in “Long-Term Debt” on our condensed consolidated balance sheets and will be amortized over the life of the notes. The net cash proceeds from the issuance were $156.8 million while debt issuance costs were $2.8 million.

Table of Contents

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

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. 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. Payment of interest on these notes is payable semi-annually on January 15 and July 15 and commenced on November 25, 2009. 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. In addition, prior to January 15, 2013, 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 108.875% of the principal amount of the notes, plus accrued and unpaid interest. 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, a limitation on how much of our own common stock we may repurchase. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2012.

Interest expense on the senior notes due in 2020, including amortization of debt issuance costs and debt discount, totaled $5.2 million and $5.1 million for the three months ended September 30, 2012 and 2011, respectively, and $15.5 million and $15.4 million for the nine months ended September 30, 2012 and 2011, respectively.

Senior Notes Due In 2017. These notes consist of $250.0 million of 7.125% senior notes due in 2017, which were issued on June 1, 2007 at 100% of the principal amount and will mature on June 1, 2017. The notes are senior unsecured obligations that rank equally with all of our existing and future senior unsecured indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowing under our bank credit facility, and will rank senior to any future subordinated indebtedness of Swift Energy. Payment of 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, at a redemption price, plus accrued and unpaid interest, of 103.563% of principal, declining in twelve-month intervals to 100% in 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, a limitation on how much of our own common stock we may repurchase. We were in compliance with the provisions of the indenture governing these senior notes as of September 30, 2012.

Interest expense on the senior notes due in 2017, including amortization of debt issuance costs, totaled $4.6 million and $4.5 million for the three months ended September 30, 2012 and 2011, as well as $13.7 million and $13.6 million for the nine months ended September 30, 2012 and 2011, respectively.

Table of Contents

(6) Discontinued Operations

In August 2008, we completed the sale of our remaining New Zealand permit for $15.0 million; with three payments of $5.0 million to be received 9 months after the sale, 18 months after the sale, and 30 months after the sale. The Company initially deferred the gain on the sale due to legal claims around the transfer of this property. In July 2011, a settlement was reached and all legal claims were dismissed. As a result, in the second quarter of 2011, the Company recognized sale proceeds of $15.0 million, net of $0.6 million in capitalized costs in assets held for sale, relating to our remaining New Zealand permit. In accordance with guidance contained in FASB ASC 360-10, the results of operations for the New Zealand operations have been excluded from continuing operations and reported as discontinued operations for the current and prior periods. As of December 31, 2011, all payments under this sale agreement had been received. There is essentially no income tax expense on this gain as the Company has offsetting New Zealand tax losses that were previously unrecognized due to a valuation allowance. The Company has written off its remaining unused New Zealand tax losses.

Our income from discontinued operations, net of taxes was $14.2 million for the nine months ended September 30, 2011, which equated to $0.33 per basic and diluted share for the same period.

(7) Acquisitions and Dispositions

There were no material acquisitions or dispositions in the nine months ended September 30, 2012 and 2011, respectively.

(8) 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, 2012 and December 31, 2011, the fair value and carrying value of our senior notes was as follows (in millions):

	September 30, 2012		December 31, 2011	
	Fair Value	Carrying Value	Fair Value	Carrying Value
7.125% senior notes due in 2017	$257.5	$250.0	$254.8	$250.0
8.875% senior notes due in 2020	$243.6	$222.1	$239.6	$221.9
7.875% senior notes due in 2022	$276.9	$248.0	$252.8	$247.9

Our senior notes due in 2017, 2020 and 2022 are stated at carrying value on our financial statements. 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.

Notes to Condensed Consolidated Financial Statements
Swift Energy Company and Subsidiaries (continued)

The following table presents our assets that are measured at fair value as of December 31, 2011, and are categorized using the fair value hierarchy. 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	Quoted Prices in Active markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
December 31, 2011				
Oil Floors	$0.1	$—	$0.1	$—

Our derivatives, measured at fair value in the table above, are recorded in "Other current assets" on the accompanying condensed consolidated balance sheets. At September 30, 2012, the Company did not have any significant fair value recorded for derivative instruments.

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 include our commodity derivatives that we value using commonly accepted industry-standard models (such as Black-Scholes) which contain inputs such as contract prices, risk-free rates, volatility measurements and other observable market data that are obtained from independent third-party sources.

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

(9) 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. Any subsidiaries of Swift Energy Company, other than Swift Energy Operating, LLC, are minor.

Table of Contents

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

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and accompanying notes included in this report and our annual reports on Form 10-K for the years ended December 31, 2011 and 2010. Unless otherwise noted, both historical information for all periods and forward-looking information provided in this Management’s Discussion and Analysis relates solely to our continuing operations located in the United States, and excludes our New Zealand discontinued operations. The following information contains forward-looking statements; see “Forward-Looking Statements” on page 28 of this report.

Overview

We are an independent oil and natural gas company formed in 1979, 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 are one of the largest producers of crude oil in the state of Louisiana, and hold a large acreage position in Texas prospective for Eagle Ford shale and Olmos tight sands development. Oil production accounted for 30% of our third quarter 2012 production and 70% of our oil and gas sales, and combined production of both oil and natural gas liquids (“NGLs”) constituted 48% of our third quarter 2012 production and 83% of our oil and gas sales. This has allowed us to benefit from better margins for oil production than natural gas production during the third quarter of 2012.

Third Quarter 2012 Activities

- Hurricane Issac: Hurricane Isaac made landfall on August 28, 2012 and caused limited damage to our Lake Washington and Bay de Chene fields in southeast Louisiana. During the third quarter of 2012, we incurred approximately $0.3 million in lease operating expenses related to hurricane clean-up and repair costs. Future infrastructure repairs are not expected to require significant capital expenditures. Due to shut-in production at these fields for several weeks during September, we estimate production of 175,000 Boe has been deferred from the third quarter. For the full-year 2012, we expect approximately 50,000 Boe of additional production will be deferred as a result of shut-in production during October.
- Production: Our production volumes increased by 13% in the third quarter of 2012 when compared to volumes in the same period in 2011 as natural gas production volumes increased by 10%, NGL volumes increased by 107%, while oil volumes decreased by 7%. Sequentially, production volumes decreased slightly in the third quarter of 2012 compared to second quarter of 2012 levels as natural gas production volumes decreased by 6%, NGL volumes increased by 19% and hurricane-affected oil volumes decreased by 4%. The increase in NGL production came from our South Texas area.
- Pricing: Our weighted average sales price in the third quarter of 2012 decreased by 21% and 2% when compared to levels in the third quarter of 2011 and the second quarter of 2012, respectively. When compared to the third quarter of 2011, natural gas prices declined 32%, NGL prices declined 46% and oil prices declined 3%. When compared to the second quarter of 2012, natural gas prices increased 26%, NGL prices declined 11% and oil prices declined 5%.
- Cash provided by operating activities: For the first nine months of 2012, our cash provided by operating activities decreased by $64.8 million or 22%, when compared to the first nine months of 2011, mainly due to lower oil and natural gas prices which decreased revenue in the 2012 period.
- 2012 capital expenditures: Our capital expenditures on a cash flow basis were $575.7 million in the first nine months of 2012, compared to $368.8 million in the first nine months of 2011. The increase was mainly due to additional drilling and completion activity during the first nine months of 2012 in our South Texas core region as we drilled nine wells in our AWP Olmos field, 15 wells in our AWP Eagle Ford field, two wells in our Fasken Eagle Ford field and 17 wells in our Artesia Wells Eagle Ford field, which helped us evaluate Eagle Ford and Olmos acreage positions in those areas. We also drilled eight wells in our Southeast Louisiana area and four non-operated wells in Central

Louisiana/East Texas. The 2012 expenditures were primarily funded by $223.7 million of cash provided by operating activities, the remaining cash proceeds from our notes offering in November 2011 and borrowings under our credit facility.

- 2012 capital efficiency efforts: Our drilling efficiencies have resulted in a reduction of drilling days per well. Consequently, we are currently able to drill more wells per rig than previously expected. In line with our 2012 work plan and budget we have released three drilling rigs during 2012 and are now operating three rigs in South Texas. With our preliminary planned activity in 2013 we expect to continue to grow production in line with our long-term strategic objectives.

Table of Contents

Strategy and Outlook

- Focus on oil and liquids properties with expanded capital budget: Our inventory of drilling locations allows us to be flexible in scheduling upcoming wells in South Texas to focus on oil and natural gas liquids. Having fulfilled our near-term obligations earlier in 2012 on most of our acreage prospective for dry natural gas production, we are concentrating on our higher return, liquids rich acreage almost exclusively this year. We plan to keep three drilling rigs active in South Texas during the fourth quarter of 2012 while our full year 2012 capital expenditures are currently estimated to be approximately $695 million to $710 million.
- Increase production: Our current 2012 goal is to increase production volumes by 10% to 12% over 2011 volumes.
- Increase reserves: Our current 2012 goal is to increase proved reserves volumes by 15% to 20%, over 2011 reserves volumes.
- Financial flexibility: At September 30, 2012, we had approximately $1.7 million of cash on hand and $102.6 million of outstanding borrowings under our credit facility. In the fourth quarter of 2012, we issued an additional $150.0 million of 7.875% senior notes due on March 1, 2022, and used the proceeds from this issuance to pay down the balance on our credit facility. In the fourth quarter of 2012, we also extended our credit facility through November 1, 2017 and increased our borrowing base and commitment amount to $450.0 million, providing additional financial flexibility to execute our ongoing strategy.
- Added midstream capacity and third-party providers: Additional dedicated transportation and processing through a newly constructed third-party pipeline of a mid-stream provider (handling natural gas production from our AWP Eagle Ford and Olmos areas) became operational at the beginning of October 2011. In our Fasken area, we also secured capacity on a pipeline built in late 2010 by a mid-stream provider and in both the AWP and Fasken areas, we have secondary transportation outlets available if capacity is restricted on our primary outlets. In June 2012, we entered into an agreement for natural gas gathering and processing for our Artesia Wells Eagle Ford field.
- Capital cost saving measures: We have realized significant capital cost savings in South Texas related to pad drilling, well construction and completion re-design, sourcing and transportation of proppants as well as increased productivity of our dedicated frac spread and crew. Our supply chain program continues to be extremely important and the relationships that we have developed with our service providers are critical to our program execution.

Known Trends and Uncertainties Affecting our Business

- Recent declines in natural gas and natural gas liquids prices: Several factors, such as increases in shale and tight sands production, mild winter weather, and relatively high natural gas storage levels have led to declining natural gas prices in the fourth quarter of 2011 through 2012, with noted improvement in the third quarter of 2012. Natural gas liquids prices have also declined in recent quarters due to many of the same reasons that natural gas prices have declined. Lower natural gas and natural gas liquids prices equate to lower revenue and cash flows and might lead to reductions in our borrowing capacity. As natural gas makes up a large percentage of our reserves base on a Boe basis, lower natural gas prices in the future could lead to potential reserves reductions which could result in full-cost ceiling write-downs.
- Employee retention: As our competitors expand their workforce, we must focus more attention on keeping our highly-skilled employees. There has been and will be constant cost pressure to retain and hire these employees and these costs do not decline as rapidly and significantly as hydrocarbon prices.
- Oilfield services shortages and delays: During periods of increased levels of exploration and production in particular areas, such as we are currently experiencing in the South Texas areas, there is increased demand for drilling rigs, equipment, supplies, oilfield services, and trained and experienced personnel. The high demand in these areas can cause shortages and delays, which may raise costs and delay field development. In South Texas we have seen improvement in the availability of services as additional equipment has moved into this area.
- Long-term capital commitments: In an effort to secure longer-term agreements on drilling rigs, fracturing services, equipment and supplies, our capital commitments have become more significant than in prior periods. Although these ensure that the rigs and crews we need are available when needed, these commitments may also reduce our liquidity

in a downturn and may require us to pay above market prices for services in a declining service price environment.

Table of Contents

Results of Operations

Revenues — Three Months Ended September 30, 2012 and 2011

Our revenues in the third quarter of 2012 decreased by 10% compared to revenues in the third quarter of 2011, due to lower oil production and lower natural gas and NGL pricing, partially offset by higher natural gas and NGL production. Average oil prices we received were 3% lower than those received during the third quarter of 2011, while natural gas prices were 32% lower, and NGL prices were 46% lower.

Crude oil production was 30% and 37% of our production volumes in the third quarters of 2012 and 2011, respectively. Crude oil sales were 70% and 69% of oil and gas sales in the third quarters of 2012 and 2011, respectively. Natural gas production was 52% and 53% of our production volumes in the third quarters of 2012 and 2011, respectively. Natural gas sales were 18% and 21% of oil and gas sales in the third quarters of 2012 and 2011, respectively. The remaining production in each year 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, 2012 and 2011:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2012	2011	2012	2011
Southeast Louisiana	$42.8	$70.8	464	783
South Texas	71.5	51.2	2,173	1,424
Central Louisiana / East Texas	13.4	13.1	235	175
Other	0.2	8.0	3	160
Total	$127.9	$143.1	2,875	2,542

In the third quarter of 2012, our $15.2 million, or 11% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $26.4 million unfavorable impact on sales, with a decrease of $10.4 million attributable to the 32% decrease in natural gas prices, a decrease of $13.6 million due to the 46% decrease in NGL prices and a decrease of $2.4 million due to the 3% decrease in average oil prices received,
- Volume variances that had a $11.2 million favorable impact on sales, with a $3.0 million increase due to the 0.8 Bcf increase in natural gas production volumes, a $15.3 million increase attributable to the 0.3 million Bbl increase in NGL production volumes, partially offset by a $7.1 million decrease due to the less than 0.1 million Bbl decrease in oil 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, 2012 and 2011:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Three Months Ended September 30, 2012	870	512	9.0	2,875	$102.73	$31.29	$2.52
Three Months Ended September 30, 2011	937	247	8.1	2,542	$105.55	$57.76	$3.68

For the three months ended September 30, 2012 and 2011, we recorded a net gain of $0.2 million and $0.3 million, respectively, related to our derivative activities. This activity is recorded in “Price-risk management and other, net” on the accompanying condensed statements of operations. Had these amounts been recognized in the oil and gas sales account, our average oil price would have been $102.73 and $105.55 for the third quarters of 2012 and 2011, respectively, and our average natural gas price would have been $2.54 and $3.71 for the third quarters of 2012 and 2011, respectively.

Table of Contents

Costs and Expenses — Three Months Ended September 30, 2012 and 2011

Our expenses in the third quarter of 2012 increased $8.1 million, or 7%, compared to those in the third quarter of 2011, for the reasons noted below.

Lease Operating Expenses ("LOE"). These expenses increased $0.4 million, or 2%, compared to the level of such expenses in the third quarter of 2011. Lease operating costs increased during 2012 due to higher costs in our South Texas region related to salt water disposal, lease operators, equipment rental and remedial well work. Our lease operating costs per Boe produced were $9.27 and $10.31 for the third quarters of 2012 and 2011, respectively.

Depreciation, Depletion and Amortization ("DD&A"). These expenses increased $4.6 million, or 8% from those in the third quarter of 2011. The increase was due to a higher depletable base including higher future development costs and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $20.52 and $21.40 in the third quarters of 2012 and 2011, respectively.

General and Administrative Expenses, Net. These expenses increased $0.6 million, or 5%, from the level of such expenses in the third quarter of 2011. The increase was primarily due to higher salaries and burdens, partially offset by a lower benefit accrual and lower deferred compensation amounts. For the third quarters of 2012 and 2011, our capitalized general and administrative costs totaled $7.8 million and $7.5 million, respectively. Our net general and administrative expenses per Boe produced decreased to $4.16 per Boe in the third quarter of 2012 from $4.48 per Boe in the third quarter of 2011. The supervision fees recorded as a reduction to general and administrative expenses were $2.9 million and $3.4 million for the third quarters of 2012 and 2011, respectively.

Severance and Other Taxes. These expenses decreased $2.8 million, or 21%, from third quarter 2011 levels. Severance and other taxes, as a percentage of oil and gas sales, were approximately 8.3% and 9.5% in the third quarters of 2012 and 2011, respectively. The decrease was primarily due to a higher percentage of our revenues coming from production in Texas which carries a lower overall severance tax rate than Louisiana.

Interest. Our gross interest cost in the third quarter of 2012 was $15.7 million, of which $2.0 million was capitalized. Our gross interest cost in the third quarter of 2011 was $10.4 million, of which $2.0 million was capitalized. The increase in interest came from our new senior notes due in 2022, which were issued in November 2011.

Income Taxes. Our effective income tax rate was 43.7% and 37.9% for the third quarters of 2012 and 2011, respectively. The primary upward adjustments in the effective tax rate above the U.S. statutory rate are for the provision for state income taxes (computed net of the offsetting federal benefit) and non-deductible equity compensation.

Net Income. Our third quarter 2012 net income of $3.1 million decreased in comparison to our third quarter 2011 net income of $17.0 million.

Revenues — Nine Months Ended September 30, 2012 and 2011

Our revenues in the first nine months of 2012 decreased by 10% compared to revenues in the first nine months of 2011, due to lower oil production and lower natural gas pricing, partially offset by higher natural gas and NGL production. Average oil prices we received were 2% higher than those received during the first nine months of 2011, while natural gas prices were 41% lower, and NGL prices were 29% lower.

Crude oil production was 31% and 37% of our production volumes in the first nine months of 2012 and 2011, respectively. Crude oil sales were 72% and 69% of oil and gas sales in the first nine months of 2012 and 2011, respectively. Natural gas production was 54% and 51% of our production volumes in the first nine months of 2012 and 2011, respectively. Natural gas sales were 16% and 20% of oil and gas sales in the first nine months of 2012 and 2011, respectively. The remaining production in each year was from NGLs.

Table of Contents

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the nine months ended September 30, 2012 and 2011:

Core Regions	Oil and Gas Sales (In Millions)		Net Oil and Gas Production Volumes (MBoe)	
	2012	2011	2012	2011
Southeast Louisiana	$ 157.0	$ 219.5	1,628	2,473
South Texas	200.2	153.8	6,316	4,117
Central Louisiana / East Texas	38.3	46.5	636	728
Other	0.6	26.7	12	510
Total	$ 396.1	$ 446.5	8,592	7,828

In the first nine months of 2012, our $50.5 million, or 11% decrease in oil, NGL, and natural gas sales resulted from:

- Price variances that had a $57.9 million unfavorable impact on sales, with a decrease of $43.7 million attributable to the 41% decrease in natural gas prices, a decrease of $20.0 million due to the 29% decrease in NGL prices, partially offset by an increase of $5.8 million due to the 2% increase in average oil prices received,
- Volume variances that had a $7.4 million favorable impact on sales, with a $27.1 million decrease due to the 0.3 million Bbl decrease in oil production volumes, offset by a $14.5 million increase due to the 3.8 Bcf increase in natural gas production volumes and a $20.0 million increase attributable to the 0.4 million Bbl increase in NGL production volumes.

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, 2012 and 2011:

	Production Volume				Average Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (MBoe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
Nine Months Ended September 30, 2012	2,659	1,318	27.7	8,592	$ 107.61	$ 36.57	$ 2.23
Nine Months Ended September 30, 2011	2,915	930	23.9	7,828	$ 105.43	$ 51.79	$ 3.81

During the first nine months of 2012, we recorded a net gain of $2.5 million related to our derivative activities, while during the first nine months of 2011, we recorded a net loss of $0.8 million from these 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 $108.46 and $105.24 for the nine months ended September 30, 2012 and 2011, respectively, and our average natural gas price would have been $2.24 and $3.80 for the nine months ended September 30, 2012 and 2011, respectively.

Costs and Expenses — Nine Months Ended September 30, 2012 and 2011

Our expenses in the first nine months of 2012 increased $40.6 million, or 12%, compared to those in the first nine months of 2011, for the reasons noted below.

Lease Operating Expenses (“LOE”). These expenses increased $7.0 million, or 9%, compared to the level of such expenses in the first nine months of 2011. Lease operating costs increased during 2012 due to higher workover costs in Southeast Louisiana and additional costs in our South Texas region for salt water disposal, labor, and repairs and maintenance. Our lease operating costs per Boe produced were $9.93 and $10.00 for the nine months ended September 30, 2012 and 2011, respectively.

Depreciation, Depletion and Amortization (“DD&A”). These expenses increased $18.5 million, or 11%, from those in the first nine months of 2011. The increase was due to a higher depletable base including higher future development costs and higher production volumes, partially offset by higher reserves volumes. Our DD&A rate per Boe of production was $21.14 and $20.84 in the nine months ended September 30, 2012 and 2011, respectively, resulting from increases in the per unit cost of reserves additions in 2012.

Table of Contents

General and Administrative Expenses, Net. These expenses increased $3.3 million, or 10%, from the level of such expenses in the first nine months of 2011. The increase was primarily due to higher salaries and burdens, partially offset by higher capitalized amounts. For the nine months ended September 30, 2012 and 2011, our capitalized general and administrative costs totaled $23.9 million and $21.9 million, respectively. Our net general and administrative expenses per Boe produced increased slightly to $4.19 per Boe in the first nine months of 2012 from $4.18 per Boe in the first nine months of 2011. The supervision fees recorded as a reduction to general and administrative expenses were $8.6 million and $10.0 million for the nine months ended September 30, 2012 and 2011, respectively.

Severance and Other Taxes. These expenses decreased $3.4 million, or 9%, from the first nine months of 2011. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9.0% and 8.8% in the nine months ended September 30, 2012 and 2011, respectively, due to a higher percentage of our revenues coming from oil production, which carries a higher severance tax rate.

Interest. Our gross interest cost in the first nine months of 2012 was $46.5 million, of which $6.0 million was capitalized. Our gross interest cost in the first nine months of 2011 was $31.2 million, of which $5.7 million was capitalized. The increase in interest came from our new senior notes due in 2022, which were issued in November 2011.

Income Taxes. Our effective income tax rate was 41.2% and 37.2% for the nine months ended September 30, 2012 and 2011, respectively. The primary upward adjustments in the effective tax rate above the U.S. statutory rate are for the provision for state income taxes (computed net of the offsetting federal benefit) and non-deductible equity compensation.

Net Income. Net income for the first nine months of 2012 was $9.7 million, which decreased in comparison to net income of $78.2 million for the first nine months of 2011.

Liquidity and Capital Resources

Net Cash Provided by Operating Activities. For the first nine months of 2012, our net cash provided by operating activities was $223.7 million, representing a 22% decrease compared to $288.5 million generated during the same period of 2011. The $64.8 million change was mainly due to lower oil production and lower natural gas pricing.

Existing Credit Facility. After the regularly scheduled review of our credit facility on October 31, 2012, the Company's borrowing base was increased to $450.0 million from the previous borrowing base amount of $330.0 million. The borrowing base was automatically decreased from $375.0 million to $330.0 million after the issuance of an additional $150.0 million of 7.875% senior notes due on March 1, 2022. The Company had previously maintained a commitment amount of $300.0 million at September 30, 2012 which was increased to $450.0 million during this recent review. The maturity of the credit facility was also extended to November 1, 2017 from May 12, 2016.

At September 30, 2012 we had $102.6 million outstanding borrowings under our credit facility. Our available borrowings under our credit facility provide us liquidity. 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.

2012 Debt Issuance. On October 3, 2012, we issued an additional $150.0 million of 7.875% senior notes due on March 1, 2022. The notes were issued at 105% of par, which equates to a yield to worst of 6.993%. The proceeds from this debt issuance were used to pay down the balance on our credit facility which increased our available liquidity.

2011 Debt Issuance. We issued $250.0 million of 7.875% senior notes due in 2022 in November 2011 at 99.156% of face value. The proceeds from this debt issuance were recorded in “Cash and cash equivalents” on the accompanying condensed consolidated balance sheet at December 31, 2011 and were used to fund capital expenditures in 2012.

Financial Ratios

Working Capital and Debt to Capitalization Ratio. Our working capital decreased from a surplus of $116.4 million at December 31, 2011, to a deficit of $134.2 million at September 30, 2012. The change primarily resulted from a decrease in cash and cash equivalents as we used cash received from our debt offering in November 2011 to fund ongoing operations including our 2012 capital program. 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 45% and 42% at September 30, 2012 and December 31, 2011, respectively.

Table of Contents

Contractual Commitments and Obligations

During the second quarter of 2012, the Company entered into additional gas transportation and processing agreements. Minimum commitments under these agreements total approximately $36.7 million as follows: 2013 - $6.6 million, 2014 - $7.4 million, 2015 - $4.7 million and approximately $3.6 million per year from 2016 through 2020. We have had no other material changes to 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, 2011.

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 on a country-by-country basis 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, 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 and the effects of hedging, 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. See the discussion above related to reserves estimation.

Given the volatility of oil and natural gas prices, it is reasonably possible that our estimate of discounted future net cash flows from proved oil and natural gas reserves could continue to change in the near-term. If oil and natural gas prices decline from the prices used in the Ceiling Test, even if only for a short period, it is reasonably possible that non-cash write-downs of oil and gas properties would occur in the future. If 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, 2012.

Table of Contents

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;
• 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, 2011. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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

Table of Contents

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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 Floors – At September 30, 2012, we had natural gas price floors in effect that cover natural gas production of 1,660,000 MMBtu from October 2012 through November 2012 with strike prices ranging from $2.92 per MMBtu to $2.97 per MMBtu.

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, 2012, we had $102.6 million drawn under our credit facility, which bears a floating rate of interest and therefore is susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 33 basis points and would not have a material adverse effect on our future cash flows.

Table of Contents

Item 4. Controls and Procedures

Disclosure Controls and Procedures

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

Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting during the first nine months of 2012 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II. - OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors.

There have been no material changes in our risk factors from those disclosed in our 2011 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 2012:

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)
07/01/12 – 07/31/12 (1)	199	$ 18.33	—	$—
08/01/12 – 08/31/12 (1)	4,204	$ 20.48	—	—
09/01/12 – 09/30/12 (1)	247	$ 19.77	—	—
Total	4,650	$ 20.35	—	$—

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

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosures.

None.

Item 5. Other Information.

None.

Item 6. Exhibits.

10.1	Amendment No. 7 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 11, 2012, File No. 1-08754).
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.

*Filed herewith

Table of Contents

SIGNATURES

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

		SWIFT ENERGY COMPANY (Registrant)
Date:	November 1, 2012	By: /s/ Alton D. Heckaman, Jr. Alton D. Heckaman, Jr. Executive Vice President and Chief Financial Officer
Date:	November 1, 2012	By: /s/ Barry S. Turcotte Barry S. Turcotte Vice President, Controller and Principal Accounting Officer

Table of Contents

Exhibit Index

10.1	Amendment No. 7 to the Swift Energy Company First Amended and Restated 2005 Stock Compensation Plan (incorporated by reference as Exhibit 10.1 to Swift Energy Company's Form 8-K filed May 11, 2012, File No. 1-08754).
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.

*Filed herewith