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Other comprehensive (loss) income

(616)	26,701	(1,372)	6,691

Comprehensive income				
	$17,073	$58,649	$115,583	$75,036

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Nine Months Ended September 30, 2012	2011
Cash flows from operating activities:		
Net income	$ 116,955	$ 68,345
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	107,328	92,041
Deferred income taxes	66,160	36,547
Amortization of deferred loan fees recorded as interest expense	2,310	1,730
Stock-based compensation expense	12,036	15,380
Derivative instruments	(19,069)	(4,208)
Change in operating assets and liabilities:		
Accounts receivable	(10,069)	(19,848)
Prepaid expenses	(223)	(596)
Other current assets	278	309
Long-term assets	650	(79)
Accounts payable	(1,377)	(3,501)
Accrued liabilities	(18,665)	3,375
Royalties and other payables	5,062	11,755
Other long-term liabilities	(2,086)	520
Net cash provided by operating activities	259,290	201,770
Cash flows from investing activities:		
Additions to oil and gas assets	(458,523)	(271,770)
Disposals of oil and gas assets	88,489	240,620
Net cash used in investing activities	(370,034)	(31,150)
Cash flows from financing activities:		
Borrowings on Credit Facility	210,000	
Payments on Credit Facility	(70,000)	(100,000)
Payments on Restated Term Loan	(20,000)	
Deferred loan fees	(1,979)	(3,197)
Proceeds from stock options exercised	898	2,017
Purchases of treasury stock	(6,048)	(4,206)
Net cash provided by (used in) financing activities	112,871	(105,386)
Net increase in cash	2,127	65,234
Cash and cash equivalents, beginning of period	47,050	41,634
Cash and cash equivalents, end of period	$ 49,177	$ 106,868
Supplemental disclosures:		
Capital expenditures included in accrued liabilities	$ 92,222	$ 80,045

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Stockholders Equity

(In thousands, except share amounts)

(Unaudited)

	Common Stock		Additional Paid-In Capital	Treasury Stock		Accumulated Other Comprehensive (Loss)/Income	Retained Earnings / Accumulated Deficit	Total Stockholders Equity
	Shares	Amount		Shares	Amount			
Balance at December 31, 2011	52,630,483	$ 52	$ 810,794	450,173	$ (11,296)	$ 1,632	$ (168,346)	$ 632,836
Stock options exercised	67,862	1	898					899
Treasury stock employee tax payment				128,675	(6,048)			(6,048)
Stock-based compensation			12,258					12,258
Vesting of restricted stock	416,486							
Comprehensive (loss) income						(1,372)	116,955	115,583
Balance at September 30, 2012	53,114,831	$ 53	$ 823,950	578,848	$ (17,344)	$ 260	$ (51,391)	$ 755,528

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Notes to Consolidated Financial Statements (unaudited)

(1) Organization and Operations of the Company

Nature of Operations. Rosetta Resources Inc. (together with its consolidated subsidiaries, the Company) is an independent exploration and production company engaged in the acquisition and development of onshore energy resources in the United States of America. The Company s operations are primarily located in South Texas, including its largest producing area in the Eagle Ford shale.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of normal recurring adjustments necessary to fairly state the financial statements, have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the U.S. (GAAP). These financial statements and notes should be read in conjunction with the Company s audited Consolidated Financial Statements and the notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2011 (2011 Annual Report).

Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income.

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2011 Annual Report.

Recent Accounting Developments

The following recently issued accounting developments have been applied or may impact the Company in future periods.

Fair Value Measurements. In May 2011, the Financial Accounting Standards Board (FASB) further expanded authoritative guidance clarifying common requirements for measuring fair value instruments and for disclosing information about fair value measurements in accordance with GAAP and International Financial Reporting Standards (IFRS). This guidance requires disclosure of quantitative and qualitative information about unobservable inputs used in measuring the fair value of Level 3 instruments. The Company adopted this guidance effective January 1, 2012. This guidance requires additional disclosures but did not impact the Company s consolidated financial position, results of operations or cash flows. See Note 5 Fair Value Measurements.

Comprehensive Income. In June 2011, the FASB issued authoritative guidance to increase the prominence of items reported in other comprehensive income. This guidance requires an entity to present components of other comprehensive income either in a single continuous statement or in two separate but consecutive statements of net income and comprehensive income. Irrespective of the presentation method chosen, an entity will be required to present on the face of the financial statement reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement where the component is presented. In December 2011, the FASB issued additional guidance deferring the effective date related to the presentation of reclassification adjustments only. The Company adopted the provisions of this guidance effective January 1, 2012, excluding the requirements deferred in the December 2011 guidance, and has presented two separate but consecutive statements of net income and comprehensive income.

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(3) Property and Equipment

The Company s total property and equipment consists of the following:

	September 30, 2012	December 31, 2011
	(In thousands)	
Proved properties	$ 2,717,071	$ 2,297,312
Unproved/unevaluated properties	65,559	141,016
Gas gathering systems and compressor stations	91,768	38,580
Other fixed assets	10,000	9,494
Total property and equipment, gross	2,884,398	2,486,402
Less: Accumulated depreciation, depletion, and amortization, including impairment	(1,761,098)	(1,657,841)
Total property and equipment, net	$ 1,123,300	$ 828,561

On February 15, 2012, the Company entered into an agreement to sell its Lobo assets and a portion of its Olmos assets for $95.0 million, subject to customary adjustments and the receipt of appropriate consents for assignment. During the third quarter of 2012, the Company closed on the sale of the final portion of the properties. Proceeds from the closing of the divestiture were recorded as adjustments to the full cost pool, with no gain or loss recognized.

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $1.2 million and $1.1 million of internal costs for the three months ended September 30, 2012 and 2011, respectively, and $4.7 million and $3.5 million for the nine months ended September 30, 2012 and 2011, respectively.

Oil and gas properties include costs of $65.6 million and $141.0 million as of September 30, 2012 and December 31, 2011, respectively, which were excluded from amortized capitalized costs. These amounts primarily represent acquisition costs of unproved properties and unevaluated exploration projects in which the Company owns a direct interest. During the second quarter of 2012, exploration work was completed in the Southern Alberta Basin and the Company s assessment indicated an impairment. As a result, accumulated costs of approximately $82.8 million were transferred to the full cost pool.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and gas assets within its U.S. cost center. The Company s ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of September 30, 2012, which were based on a West Texas Intermediate oil price of $91.48 per Bbl and a Henry Hub natural gas price of $2.83 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and gas properties. As a result, no write-down was recorded as of September 30, 2012. It is possible that a write-down of the Company s oil and gas properties could occur in future periods in the event that oil and natural gas prices decline or the Company experiences significant downward adjustments to its estimated proved reserves.

(4) Commodity Derivative Contracts and Other Derivatives

The Company is exposed to various market risks, including volatility in oil, natural gas liquids (NGL) and natural gas prices, which are managed through derivative instruments. The level of derivative activity utilized depends on market conditions, operating strategies and available derivative prices. The Company utilizes various types of derivative instruments to manage commodity price risk, including fixed price swaps, basis swaps, New York Mercantile Exchange (NYMEX) roll swaps and costless collars. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company s oil, NGL and natural gas production.

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As of September 30, 2012, the following derivative contracts were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total Notional Volume Bbl	Average Floor Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2012	Costless Collar	7,600	699,200	$ 78.82	$ 115.02
Crude oil	2013	Costless Collar	7,750	2,828,750	80.16	115.71
Crude oil	2014	Costless Collar	3,000	1,095,000	83.33	109.63
				4,622,950		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total Notional Volume Bbl	Fixed Prices per Bbl
Crude oil	2012	Basis Swap	2,500	230,000	$ 8.70
Crude oil	2012	NYMEX Roll Swap	2,500	230,000	(0.30)
Crude oil	2013	Basis Swap	1,875	684,375	5.80
Crude oil	2013	NYMEX Roll Swap	1,875	684,375	(0.18)
				1,828,750	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total Notional Volume Bbl	Fixed Prices per Bbl
NGL-Propane	2012	Swap	2,500	230,000	$ 53.22
NGL-Isobutane	2012	Swap	760	69,920	71.70
NGL-Normal Butane	2012	Swap	780	71,760	67.86
NGL-Pentanes Plus	2012	Swap	660	60,720	89.77
NGL-Ethane	2013	Swap	1,000	365,000	14.15
NGL-Propane	2013	Swap	2,270	828,550	46.34
NGL-Isobutane	2013	Swap	550	200,750	69.76
NGL-Normal Butane	2013	Swap	570	208,050	68.13
NGL-Pentanes Plus	2013	Swap	610	222,650	87.35
NGL-Propane	2014	Swap	1,035	377,775	45.66
NGL-Isobutane	2014	Swap	325	118,625	67.43
NGL-Normal Butane	2014	Swap	315	114,975	66.12
NGL-Pentanes Plus	2014	Swap	325	118,625	86.33
				2,987,400	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume MMBtu	Total Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu
Natural gas	2012	Costless Collar	20,000	1,840,000	$ 5.13	$ 6.31
Natural gas	2013	Swap	10,000	3,650,000	$ 3.95	

Natural gas	2014	Swap	20,000	7,300,000	$	3.98
Natural gas	2015	Swap	10,000	3,650,000	$	3.95
				16,440,000		

Subsequent to September 30, 2012, the Company entered into additional derivative positions for natural gas and NGL production, including the ethane component of the NGL barrel.

As of September 30, 2012, the Company s derivative instruments are with counterparties who are lenders under the Company s credit facilities or were lenders under the Company s credit facilities upon origination of the derivative instrument. This allows the Company to satisfy any need for margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its credit facilities, thus eliminating the need for independent collateral postings. The Company s

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ability to continue satisfying any applicable margin requirements in this manner may be subject to change as described in Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Government Regulation. As of September 30, 2012, the Company had no deposits for collateral relating to its commodity derivative positions.

Discontinuance of Hedge Accounting

Effective January 1, 2012, the Company elected to de-designate all commodity contracts that were previously designated as cash flow hedges as of December 31, 2011, and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included $2.6 million ($1.6 million after tax) of unrealized net gains, representing the mark-to-market value of the Company s cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and are to be reclassified into earnings in future periods as the underlying hedged transactions affect earnings. During the three and nine months ended September 30, 2012, the Company reclassified unrealized net gains of $1.0 million ($0.6 million after tax) and $2.2 million ($1.4 million after tax), respectively, into earnings from Accumulated other comprehensive income. The Company expects to reclassify an additional $0.5 million ($0.3 million after tax) of unrealized net gains during the last three months of 2012 and $0.1 million of unrealized net losses during 2013 into earnings from Accumulated other comprehensive income.

With the election to de-designate hedging instruments, all of the Company s derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings rather than in Accumulated other comprehensive income. These mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The cash flow impact occurs upon settlement of the underlying contract.

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Additional Disclosures about Derivative Instruments and Hedging Activities

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the Company s financial statements. The following table sets forth information on the location and amounts of the Company s derivative instrument fair values in the Consolidated Balance Sheet as of September 30, 2012 and December 31, 2011, respectively:

Commodity derivative contracts	Location on Consolidated Balance Sheet	Asset (Liability) Fair Value September 30, 2012	Asset (Liability) Fair Value December 31, 2011
		(in thousands)	
Oil	Derivative instruments - current assets	$	$ (2,937)
Oil	Derivative instruments - non-current assets		1,254
Oil	Derivative instruments - current liabilities		(695)
Oil	Derivative instruments - long-term liabilities		(167)
NGL	Derivative instruments - current assets		(1,029)
NGL	Derivative instruments - current liabilities		(6,948)
NGL	Derivative instruments - long-term liabilities		(1,184)
Natural gas	Derivative instruments - current assets		14,137
Total derivatives designated as hedging instruments		$	$ 2,431
Oil	Derivative instruments - current assets	$ (2,085)	$
Oil	Derivative instruments - non-current assets	4,594	379
Oil	Derivative instruments - current liabilities		855
NGL	Derivative instruments - current assets	10,637	
NGL	Derivative instruments - non-current assets	5,677	
Natural gas	Derivative instruments - current assets	3,974	
Natural gas	Derivative instruments - non-current assets	(2,219)	
Total derivatives not designated as hedging instruments		$ 20,578	$ 1,234
Total derivatives		$ 20,578	$ 3,665

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The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the three and nine months ended September 30, 2012 and 2011, respectively:

Location on Consolidated Statement of Operations	Description of Gain (Loss)	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011 (1)	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011 (1)
			(in thousands)		
Oil sales	Loss reclassified from Accumulated OCI	$	$ (181)	$	$ (1,635)
NGL sales	Loss reclassified from Accumulated OCI		(3,178)		(7,403)
Natural gas sales	Gain reclassified from Accumulated OCI		2,450		12,854
Natural gas sales (2)	Gain recognized in income				11,018
Derivative instruments	Gain recognized in income	7,624		16,866	
	Realized gain (loss) recognized in income	$ 7,624	$ (909)	$ 16,866	$ 14,834
Derivative instruments (3)	(Loss) gain recognized in income due to changes in fair value	$ (36,414)	$ (1,901)	$ 16,913	$ (6,685)
Derivative instruments	Gain reclassified from Accumulated OCI	967		2,156	
	Unrealized (loss) gain recognized in income	$ (35,447)	$ (1,901)	$ 19,069	$ (6,685)
	Total commodity derivative (loss) gain recognized in income	$ (27,823)	$ (2,810)	$ 35,935	$ 8,149

(1) Includes realized gains (losses) from derivative instruments designated as hedging instruments. Effective January 1, 2012, the Company de-designated all commodity contracts and discontinued hedge accounting.

(2) For the nine months ended September 30, 2011, amount represents the realized gains associated with the termination of derivatives in 2011 used to hedge production from the Company s divested DJ Basin and Sacramento Basin properties.

(3) For the three and nine months ended September 30, 2011, amounts represent the unrealized loss associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps, which did not qualify for hedge accounting.

As a result of the Company s election to de-designate all commodity contracts that were previously designated as cash flow hedges as of December 31, 2011 and to discontinue hedge accounting prospectively, the Company recognized no gain or loss in Accumulated other comprehensive income for the three and nine months ended September 30, 2012. The Company recognized unrealized gains of $40.7 million and $24.9 million, respectively, in Accumulated other comprehensive income for the three and nine months ended September 30, 2011.

(5) Fair Value Measurements

The Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company measures its non-financial assets and liabilities, such as asset retirement obligations and other property and equipment, at fair value on a non-recurring basis.

As defined in the FASB s guidance, fair value is the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). To estimate fair value, the Company utilizes market data and assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The FASB s guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are as follows:

Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.

Level 3 inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

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As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities along with their placement within the fair value hierarchy levels. The Company determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period.

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis for the respective period:

	Fair value as of September 30, 2012			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets (liabilities):				
Money market funds (1)	$	$ 1,035	$	$ 1,035
Commodity derivative contracts			20,578	20,578
Total	$	$ 1,035	$ 20,578	$ 21,613

	Fair value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets (liabilities):				
Money market funds	$	$	$ 1,035	$ 1,035
Commodity derivative contracts			3,665	3,665
Total	$	$	$ 4,700	$ 4,700

(1) The value related to the money market funds was transferred from Level 3 to Level 2 as a result of the Company s ability to obtain independent market-corroborated data. The Company recognized the transfer between Level 3 and Level 2 during the first quarter of 2012.

The Company s Level 3 instruments include commodity derivative contracts which are measured based upon counterparty and third-party broker quotes. Although the Company reviews the fair values derived from counterparties and third-party brokers with publicly available values for relevant NYMEX futures contracts and exchange traded contracts for each derivative settlement location, the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments and does not have access to the specific valuation models or certain inputs used by its counterparties or third-party brokers.

The following table presents a range of the unobservable inputs utilized in the fair value measurements of the Company s assets and liabilities classified as Level 3 instruments as of September 30, 2012:

Level 3 Instrument	Asset (Liability)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Weighted Average
Oil NYMEX roll swap	$ 48	Discounted cash flow	Forward price curve - NYMEX roll swaps	$ 0.14	$ 0.28	$ 0.21
Oil NYMEX roll swap	(131)	Discounted cash flow	Forward price curve - NYMEX roll swaps	(0.54)	0.35	(0.19)
Oil basis swaps	(6,172)	Discounted cash flow	Forward price curve - basis swaps	7.86	19.83	13.31
Oil costless collars	8,763	Option model	Forward price curve - costless collar option value	(7.02)	10.18	1.91
NGL swaps	16,709	Discounted cash flow	Forward price curve - swaps	38.54	84.84	53.32
NGL swaps	(395)	Discounted cash flow	Forward price curve - swaps	14.60	15.70	15.24
Natural gas swaps	578	Discounted cash flow	Forward price curve - swaps	3.67	4.10	3.79
Natural gas swaps	(2,226)	Discounted cash flow	Forward price curve - swaps	3.99	4.52	4.18
Natural gas costless collars	3,404	Option model			2.79	1.86

		Forward price curve - costless collar option value
	$ 20,578	

The determination of derivative fair values also incorporates a credit adjustment for nonperformance risk, including the credit standing of the counterparties involved, the impact of credit enhancements and the impact of the Company s nonperformance risk on its liabilities. The Company considered credit adjustments for its counterparties using their current credit default swap values in determining fair value and recorded a downward adjustment to the fair value of its derivative instruments in the amount of $0.1 million as of September 30, 2012.

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The significant unobservable inputs for Level 3 derivative contracts include forward price curves, option values and credit risk adjustments. Significant increases (decreases) in the quoted forward prices for commodities, option values and credit risk adjustments generally lead to corresponding decreases (increases) in the fair value measurement of the Company s oil, NGL and natural gas derivative contracts.

The tables below present reconciliations of financial assets and liabilities classified as Level 3 in the fair value hierarchy during the indicated periods.

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2012	$ 3,665	$ 1,035	$ 4,700
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	33,779		33,779
Purchases, Issuances and Settlements:			
Settlements	(16,866)		(16,866)
Transfers in and out of Level 3 (1)		(1,035)	(1,035)
Balance at September 30, 2012	$ 20,578	$	$ 20,578

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability)	Total
		(In thousands)	
Balance at January 1, 2011	$ 19,657	$ 1,035	$ 20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (2)	(22,623)		(22,623)
Included in Other Comprehensive Income	24,873		24,873
Purchases, Issuances and Settlements:			
Settlements	(8,281)		(8,281)
Purchases	11,018		11,018
Balance at September 30, 2011	$ 24,644	$ 1,035	$ 25,679

(1) The value related to the money market funds was transferred from Level 3 to Level 2 as a result of the Company s ability to obtain independent market-corroborated data. The Company recognized the transfer between Level 3 and Level 2 during the first quarter of 2012.
(2) Includes an unrealized derivative loss of $6.7 million associated with the change in fair value of the Company s crude oil basis and NYMEX roll swaps, which did not qualify for hedge accounting.

Fair Value of Other Financial Instruments

All of the Company s financial instruments, except derivatives, are presented on the balance sheet at carrying value. As of September 30, 2012, the carrying value of cash and cash equivalents (excluding money market funds), other current assets and current liabilities reported in the consolidated balance sheet approximate fair value because of their short-term nature and are considered Level 1 instruments.

The Company s debt consists of publicly traded Senior Notes (defined below) and borrowings under the Credit Facility (defined below). The fair value of the Company s Senior Notes is based upon an unadjusted quoted market price and is considered a Level 1 instrument. The Company s borrowings under the Credit Facility approximate fair value as the interest rates are variable and reflective of market rates and are therefore considered a Level 1 instrument. As of September 30, 2012, the carrying amount and estimated fair value of total debt was $370.0 million and $392.3 million, respectively.

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(6) Asset Retirement Obligations

The following table provides a roll forward of the Company s asset retirement obligations. Liabilities incurred during the period include additions to obligations. Liabilities settled during the period include settlement payments for obligations as well as obligations that were assumed by the purchasers of divested properties. Activity related to the Company s asset retirement obligations (ARO) is as follows:

	Nine Months Ended September 30, 2012 (In thousands)
ARO as of December 31, 2011	$ 14,313
Liabilities incurred during period	110
Liabilities settled during period	(8,600)
Revision of previous estimates	2,067
Accretion expense	683
ARO as of September 30, 2012	$ 8,573

As of September 30, 2012, the $1.9 million current portion of the total ARO is included in Accrued liabilities, and the $6.7 million long-term portion of ARO is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Long-Term Debt

Senior Secured Revolving Credit Facility. On April 25, 2012, the Company entered into an amendment to its Amended and Restated Senior Revolving Credit Agreement (the Credit Facility). Under this amendment, among other things, the Company s borrowing base and commitments were increased from $325.0 million to $625.0 million and the Company s capacity to hedge its production was increased. Availability under the Credit Facility is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on the Company s hedging arrangements as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including the Company s level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a significant reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base.

As of September 30, 2012, the Company had $170.0 million outstanding with $455.0 million of available borrowing capacity under its Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50%. The weighted average borrowing rate for the nine months ended September 30, 2012 under the Credit Facility was 1.91%. Borrowings under the Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company s assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 reserve value, a guaranty by all of the Company s domestic subsidiaries and a pledge of 100% of the membership and limited partnership interests of the Company s domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. The Company is subject to certain financial covenants such as the requirement to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. As of September 30, 2012, the Company s current ratio was 3.4 and the leverage ratio was 0.9. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales and liens on properties.

In October 2012, the Company borrowed and repaid an additional $20.0 million under the Credit Facility. After repayment, the available borrowing capacity was $455.0 million.

Second Lien Term Loan. The Company s amended and restated term loan (the Restated Term Loan) of $20.0 million was prepaid in full on August 31, 2012. Outstanding fixed-rate borrowings under the Restated Term Loan bore interest at 13.75% and would have matured on October 2, 2012. The loan was collateralized by second priority liens on substantially all of the Company s assets and upon prepayment, the second priority liens were released. In connection with the prepayment of the Restated Term Loan, $0.2 million of prepayment fees were incurred and have been reflected as a component of interest expense.

Senior Notes. On April 15, 2010, the Company issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the Senior Notes) in a private offering. The Senior Notes were issued under an indenture (the Indenture) with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit the Company s ability to, among other things,

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incur additional indebtedness; pay dividends on capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of the Company s restricted subsidiaries to pay dividends, make loans or transfer property to the Company; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. Interest is payable on the Senior Notes semi-annually on April 15 and October 15. On September 21, 2010, the Company exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

As of September 30, 2012, the Company had total outstanding borrowings of $370.0 million. For the nine months ended September 30, 2012, the Company s weighted average borrowing rate was 7.65%.

(8) Income Taxes

The Company s effective tax rate for the three and nine months ended September 30, 2012 was 35.5% and 36.1%, respectively, and the effective tax rate for the three and nine months ended September 30, 2011 was 35.8% and 35.0%, respectively. The provision for income taxes for the three and nine months ended September 30, 2012 differs from the tax computed at the federal statutory income tax rate primarily due to the impact of state income taxes and the non-deductibility of certain incentive compensation. As of September 30, 2012 and December 31, 2011, the Company had no unrecognized tax benefits. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2012, the Company had a net deferred tax asset of $19.8 million resulting primarily from net operating loss carryforwards and the difference between the book basis and tax basis of oil and natural gas properties. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards. The Company will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

(9) Commitments and Contingencies

Firm Oil and Gas Transportation and Processing Commitments. The Company has various production volume transportation and processing commitments related to its operations in the Eagle Ford shale and has an aggregate minimum commitment to deliver 7.8 MMBbls of oil by the end of 2017 and 405 million MMBtus of natural gas by the end of 2023. The Company will be required to make periodic deficiency payments for any shortfalls in delivering the minimum volume under these commitments. As of September 30, 2012, the Company has accrued deficiency fees of $4.2 million and expects to continue to accrue additional deficiency fees. Future obligations under firm oil and natural gas transportation and processing agreements as of September 30, 2012 are as follows:

	September 30, 2012 (In thousands)
2012	$ 2,277
2013	25,629
2014	33,717
2015	33,717
2016	33,799
Thereafter	167,655
	$ 296,794

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors to execute the Company s Eagle Ford shale drilling program, and payments under these commitments are accounted for as capital additions to oil and gas properties. As of September 30, 2012, the Company had no outstanding drilling rig commitments with terms greater than one year and minimum contractual commitments due in the next twelve months are $7.0 million. As of September 30, 2012, the Company s minimum contractual commitments for completion services agreements for the stimulation, cementing and delivery of drilling fluids are $7.8 million.

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Contingencies. The Company is party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability the Company may ultimately incur with respect to any such proceeding may be in excess of amounts currently accrued, if any. After considering the Company s available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, management does not believe any such matter will have a material adverse effect on the Company s financial position, results of operations or cash flows.

(10) Earnings Per Share

Basic earnings per share (EPS) is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the period. Diluted EPS reflects the potential dilution that could occur if outstanding common stock awards and stock options were exercised at the end of the period.

The following is a calculation of basic and diluted weighted average shares outstanding:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)			
Basic weighted average number of shares outstanding	52,534	52,038	52,478	51,962
Dilution effect of stock option and awards at the end of the period	349	589	385	631
Diluted weighted average number of shares outstanding	52,883	52,627	52,863	52,593
Anti-dilutive stock awards and shares	1	6	2	3

(11) Stock-Based Compensation Expense

Stock-based compensation expense includes the expense associated with restricted stock granted to employees and directors and the expense associated with the Performance Share Units (PSUs) granted to executive management. As of the indicated dates, stock-based compensation expense consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(in thousands)			
Total stock-based compensation expense	$ 6,453	$ (590)	$ 12,258	$ 15,884
Capitalized in oil and gas properties	101	(162)	(222)	(504)
Net stock-based compensation expense	$ 6,554	$ (752)	$ 12,036	$ 15,380

All stock-based compensation expense associated with restricted stock granted to employees and directors is recognized on a straight-line basis over the applicable remaining vesting period. For the three and nine months ended September 30, 2012, the Company recorded compensation expense of approximately $2.0 million and $4.7 million, respectively, related to these equity awards. As of September 30, 2012, unrecognized stock-based compensation expense related to unvested restricted stock was approximately $7.5 million.

Stock-based compensation expense associated with the PSUs granted to executive management is recognized over a three-year performance period. For the three and nine months ended September 30, 2012, the Company recognized compensation expense of $4.5 million and $7.5 million, respectively, associated with the PSUs. At the current fair value as of September 30, 2012 and assuming that the Board elects the maximum available payout of 200% for all PSU metrics, unrecognized stock-based compensation expense related to the PSUs was approximately $16.8 million. The Company s total stock-based compensation expense will be measured and adjusted quarterly until settlement occurs, based on the Company s performance and quarter-end closing common stock prices. For a more detailed description of the Company s PSU plans, including related performance and market conditions and structure, see the definitive proxy statement filed with respect to the

Company s 2012 annual meeting under the heading Compensation Discussion and Analysis and the Company s 2011 Annual Report.

(12) Guarantor Subsidiaries

The Company s Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several and the Company s non-guarantor subsidiaries are minor. In addition, there are no restrictions on the ability of the Company to obtain funds from its subsidiaries by dividend or loan. Finally, none of the Company s subsidiaries has restricted assets that exceed 25% of net assets as of the most recent fiscal year which may not be transferred to the Company in the form of loans, advances or cash dividends by the subsidiaries without the consent of a third party.

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements regarding the Company within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical fact included in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, would, expect, plan, project, intend, anticipate, predict, potential, pursue, target or continue, the negative of such terms or variations thereon, or other comparable terminology. Unless the context clearly indicates otherwise, references in this report to Rosetta, the Company, we, our, us or like terms refer to Rosetta Resources In and its subsidiaries.

The forward-looking statements contained in this report reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends, and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management s assumptions about future events may prove to be inaccurate. For a more detailed description of the risks and uncertainties involved, see Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011 (the 2011 Annual Report). We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for oil, natural gas liquids (NGLs) and natural gas;
- changes in the price of oil, NGLs and natural gas;
- general economic conditions, either internationally, nationally or in jurisdictions where we conduct business;
- conditions in the energy and financial markets;
- our ability to obtain credit and/or capital in desired amounts and/or on favorable terms;
- the ability and willingness of our current or potential counterparties or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the occurrence of property acquisitions or divestitures;

uncertainties and changes in reserve estimates;

inflation;

competition in the oil and natural gas industry;

the availability and cost of relevant raw materials, goods and services;

the availability and cost of processing and transportation of oil, NGLs and natural gas;

changes or advances in technology;

limitations, availability, and constraints on infrastructure required to process, transport, and market oil, NGLs and natural gas;

performance of contracted markets and companies contracted to provide processing, transportation and trucking of oil, NGLs and natural gas;

developments in oil-producing and natural gas-producing countries;

drilling and exploration risks;

legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including but not limited to changes in national healthcare, cap and trade, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, and risks and liability under federal, state and local environmental laws and regulations;

effects of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

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present and future claims, litigation and enforcement actions;

lease termination due to lack of activity or other disputes with mineral lease and royalty owners regarding the calculation and payment of royalties or otherwise;

the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;

factors that could impact the cost, extent and pace of executing our capital program, including but not limited to, access to oilfield services, access to water for hydraulic fracture stimulations, permitting delays, unavailability of required permits, lease suspensions, drilling, exploration and production moratoriums and other legislative, executive or judicial actions by federal, state and local authorities, as well as actions by private citizens, environmental groups or other interested persons;

sabotage, terrorism and border issues, including encounters with illegal aliens and drug smugglers; and

any other factors that impact or could impact the exploration of oil or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

Overview

The following discussion addresses material changes in our results of operations for the three and nine months ended September 30, 2012 compared to the three and nine months ended September 30, 2011 and material changes in our financial condition since December 31, 2011. This discussion should be read in conjunction with our 2011 Annual Report, which includes disclosures regarding our critical accounting policies as part of Management s Discussion and Analysis of Financial Condition and Results of Operations.

Results for the three months ended September 30, 2012 included the following:

production of 3.4 MMBoe compared to 2.4 MMBoe for the three months ended September 30, 2011;

25 gross (24 net) wells drilled with a net success rate of 100% compared to 16 gross (16 net) wells drilled with a net success rate of 100% for the three months ended September 30, 2011;

net income of $17.7 million, or $0.33 per diluted share, compared to $31.9 million, or $0.61 per diluted share, for the three months ended September 30, 2011.

Results for the nine months ended September 30, 2012 included the following:

production of 9.5 MMBoe compared to 7.1 MMBoe for the nine months ended September 30, 2011;

63 gross (61 net) wells drilled with a net success rate of 100% compared to 40 gross (39 net) wells drilled with a net success rate of 100% for the nine months ended September 30, 2011;

net income of $117.0 million, or $2.21 per diluted share, compared to $68.3 million, or $1.30 per diluted share, for the nine months ended September 30, 2011.

Our principal business strategy is focused on the acquisition, development and production of oil, NGLs and natural gas from unconventional resource plays. Our current assets are primarily located in the Eagle Ford shale in South Texas, one of the most active shale plays in the U.S. In the last three years, we have become a significant producer in the liquids-rich window of the region and have established an inventory of lower-risk, higher-return drilling opportunities that offer more predictable and long-term production, reserve growth and a more valuable commodity mix. In addition to our focus in the Eagle Ford shale area, we are pursuing new opportunities to drive the long-term growth and sustainability of the Company. We continue to consider investments in other unconventional resource basins that offer a viable inventory of projects including new higher-risk exploration projects and producing property acquisitions.

Our current operations in the Eagle Ford shale are focused in four areas. Our original 2009 discovery is located in the 26,500-acre Gates Ranch leasehold in Webb County. We are also active in the Karnes Trough area, the Briscoe Ranch leasehold and in Central Dimmit County, where our positions were delineated in 2010 and 2011. Overall, we hold 65,000 net acres in the region with approximately 50,000 acres located in the crude oil and liquids producing portions of the play. Rosetta was an early entrant into the Eagle Ford area, accumulating most of our acreage positions during 2008 and 2009 when the trend was still in its infancy as an unconventional resource play.

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The development of our assets in the Eagle Ford has led to substantial growth for the Company, more than doubling our reserve base in the last two years and shifting our portfolio toward greater percentages of higher-valued crude oil and NGL production. As of December 31, 2011, our total estimated proved reserves were 161 MMBoe, a 101% increase from 80 MMBoe at the prior year-end. As of September 30, 2012, approximately 55% of our reserves in the Eagle Ford shale were liquids. For the quarter ended September 30, 2012, approximately 60% of our production was from crude oil and liquids (with 49% of liquids production attributable to oil) as compared to 51% of our production from crude oil and liquids (with 37% of liquids production attributable to oil) for the same period in 2011. The development of our Eagle Ford assets combined with the sale of non-strategic assets continues to lower our overall cost structure as a company, with lease operating expenses for the first nine months of 2012 decreasing to $3.09 per Boe from $3.93 per Boe for the same period in 2011.

We successfully drilled 25 and completed 16 wells in the Eagle Ford shale during the quarter ended September 30, 2012. As of that date, we had completed a total of 107 wells in the Eagle Ford shale. In the first nine months of 2012, daily production increased 33% from the same period in 2011, and we continue to record strong sequential growth in our Eagle Ford volumes. We have developed multiple options for transportation and processing capacity to handle our increased production, with firm commitments in place to meet total planned production levels for the next two years.

With our shift to an unconventional resource strategy, we have streamlined our operations by divesting of assets that no longer fit our operating model. Since 2010, we have executed sale agreements for aggregate consideration of approximately $440 million. During the first nine months of 2012, we divested our Lobo assets and a portion of our Olmos properties in South Texas for $95 million, subject to customary closing adjustments, with a January 1, 2012 effective date.

During the second quarter of 2012, our exploratory drilling program in the Southern Alberta Basin in Northwest Montana was concluded. Of the seven horizontal wells that were drilled, five were completed. Based on results that were below our targeted type curve, we have suspended all capital activity for exploration in the area. Our Southern Alberta Basin position has leases and lease options that will begin to expire in January 2014.

Our 2012 capital program is expected to range from $660 to $680 million compared to our original $640 million budget. The incremental $20 million to $40 million is dependent on the timing of several activities. These include the drilling of two non-Eagle Ford exploration wells, the funding of anticipated land acquisitions both inside and outside of the Eagle Ford, and the additional costs incurred in 2012 associated with the planned move of our corporate office in 2013. The projection also reflects expenditures for our share of costs for 12 outside operated Eagle Ford wells planned to be drilled in the fourth quarter of 2012 and for the construction of additional facilities to support expected 2013 Eagle Ford development.

While our unconventional resource strategy is proving to be successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Although we cannot completely control all external factors that could affect our operating environment, our business model takes into account the threats that could impede achievement of our stated growth objectives and the building of our asset base. We have diversified our production base to include a greater mix of crude oil and NGLs, which continue to be priced at more favorable levels than natural gas. With our high concentration of production located in the Eagle Ford shale, we have taken various steps to provide access to necessary services and infrastructure. We believe that our 2012 capital program can be executed from internally generated cash flows, cash on hand, drawing on unused capacity under our existing Credit Facility and the proceeds from our recent asset divestitures. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs. If our internal funds are insufficient to meet projected funding requirements, we would consider curtailing capital spending or accessing the capital markets.

Availability under our Credit Facility is restricted to a borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on hedging arrangements and asset divestitures. The amount of the borrowing base is dependent on a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. Subsequent to September 30, 2012, our semi-annual borrowing base redetermination was completed and our borrowing base under the Credit Facility was reconfirmed by our lenders at $625.0 million. As of November 7, 2012, we had $170.0 million of borrowings outstanding with $455.0 million available for borrowing under the Credit Facility.

Results of Operations

Revenues

Our consolidated financial statements for the three months ended September 30, 2012 reflect total revenue of $122.8 million based on total volumes of 3.4 MMBoe and net derivative losses of $27.8 million. Our consolidated financial statements for the nine months ended September 30, 2012 reflect total revenue of $435.2 million based on total volumes of 9.5 MMBoe and net derivative gains of $35.9 million.

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The following table summarizes the components of our revenues (including the effects of derivative instruments) for the periods indicated, as well as each period s production volumes and average realized prices:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	% Change Increase/ (Decrease)	2012	2011	% Change Increase/ (Decrease)
	(In thousands, except percentages unit and per amounts)			(In thousands, except percentages and per unit amounts)		
Revenues:						
Oil sales	$ 92,377	$ 33,491	176%	$ 221,574	$ 101,336	119%
NGL sales	35,179	36,411	(3%)	114,867	85,741	34%
Natural gas sales	23,019	33,256	(31%)	62,815	129,493	(51%)
Derivative instruments	(27,823)	(1,901)	(1,364%)	35,935	(6,685)	638%
Total revenues	$ 122,752	$ 101,257	21%	$ 435,191	$ 309,885	40%
Production:						
Oil (MBbls)	1,015.2	447.9	127%	2,422.7	1,215.4	99%
NGLs (MBbls)	1,036.3	746.9	39%	3,009.6	1,855.4	62%
Natural gas (Bcf)	8.2	7.0	17%	24.6	24.3	1%
Total equivalents (MBoe)	3,412.0	2,359.8	45%	9,531.4	7,125.5	34%
Average sales price:						
Oil, excluding derivatives (per Bbl)	$ 90.99	$ 75.18	21%	$ 91.46	$ 84.72	8%
Oil, including realized derivatives (per Bbl)	89.59	74.77	20%	90.35	83.38	8%
NGL, excluding derivatives (per Bbl)	33.95	53.00	(36%)	38.17	50.20	(24%)
NGL, including realized derivatives (per Bbl)	38.62	48.75	(21%)	39.98	46.21	(13%)
Natural gas, excluding derivatives (per Mcf)	2.81	4.40	(36%)	2.55	4.35	(41%)
Natural gas, including realized derivatives (per Mcf)	3.32	4.75	(30%)	3.13	5.33	(41%)
Revenue, excluding realized derivatives (per Boe)	44.13	44.10	0%	41.89	42.35	(1%)
Revenue, including realized derivatives (per Boe)	46.37	43.71	6%	43.66	44.43	(2%)

Oil. For the three and nine months ended September 30, 2012, oil revenue, including realized derivative losses, increased by $57.5 million and $117.6 million, respectively, from the same periods in 2011. The increases were attributable to increased production from newly completed wells in the Eagle Ford shale and higher average realized prices. Realized derivative losses of $1.4 million and $2.7 million, respectively, for the three and nine months ended September 30, 2012 are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2011, the effects of oil hedging activities on oil revenue resulted in losses of $0.2 million and $1.6 million, respectively, and are reported as a component of Oil sales within Revenues.

NGLs. For the three and nine months ended September 30, 2012, NGL revenues, including realized derivative gains, increased by $3.6 million and $34.6 million, respectively, from the same periods in 2011. The increases were attributable to increased production from newly completed wells in the Eagle Ford shale offset by lower average realized prices, including the effects of realized derivative gains, as compared to the same periods in 2011. Realized derivative gains of $4.8 million and $5.5 million, respectively, for the three and nine months ended September 30, 2012 are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2011, the effects of NGL hedging activities on NGL revenue resulted in losses of $3.2 million and $7.4 million, respectively, and are reported as a component of NGL sales within Revenues.

Natural Gas. For the three and nine months ended September 30, 2012, natural gas revenues, including realized derivative gains, decreased by $6.0 million and $52.6 million, respectively, from the same periods in 2011. The decreases were primarily due to a decline in average realized price of natural gas, including the effects of realized derivative gains. Realized derivative gains of $4.2 million and $14.1 million, respectively, for the three and nine months ended September 30, 2012 are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2011, the effects of natural gas hedging activities on natural gas revenues resulted in gains of $2.5 million and $23.9 million, respectively, and are reported as a component of Natural gas sales within Revenues.

Derivative Instruments**.** For the three and nine months ended September 30, 2012, Derivative instruments included an unrealized derivative loss of $35.4 million and gain of $19.1 million, respectively, due to changes in fair value on commodity derivative contracts and reclassification of commodity hedging gains from Accumulated other comprehensive income, and realized derivative gains of $7.6 million and $16.9 million, respectively, from derivative settlements. These realized derivative gains represent cash settlements associated with our commodity derivative contracts. For the three and nine months ended September 30, 2011, Derivative instruments included unrealized derivative losses of $1.9 million and $6.7 million, respectively, associated with the change in fair value of our crude oil basis and NYMEX roll swaps. These instruments did not qualify for hedge accounting, and the associated derivative loss has been reclassified from Oil sales to Derivative instruments to conform to the current year presentation.

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Operating Expenses

The following table presents information regarding our operating expenses:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	% Change Increase/ (Decrease)	2012	2011	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Lease operating expense	$ 10,697	$ 4,445	141%	$ 29,434	$ 27,975	5%
Treating and transportation	12,807	5,481	134%	37,330	13,807	170%
Production taxes	5,402	2,107	156%	11,551	6,736	71%
Depreciation, depletion and amortization (DD&A)	40,432	24,657	64%	107,328	92,041	17%
General and administrative costs	19,972	9,453	111%	48,454	46,830	3%
Costs and expenses (per Boe of production)						
Lease operating expense	$ 3.14	$ 1.88	67%	$ 3.09	$ 3.93	(21%)
Treating and transportation	3.75	2.32	62%	3.92	1.94	102%
Production taxes	1.58	0.89	78%	1.21	0.95	27%
Depreciation, depletion and amortization (DD&A)	11.85	10.45	13%	11.26	12.92	(13%)
General and administrative costs	5.85	4.01	46%	5.08	6.57	(23%)
General and administrative costs, excluding stock-based compensation	3.93	4.32	(9%)	3.82	4.41	(13%)
Production costs (1)	14.71	12.51	18%	13.72	16.13	(15%)

(1) Production costs per Boe includes lease operating expense and DD&A and excludes ad valorem taxes.

Lease Operating Expense. Lease operating expense increased $6.3 million and $1.5 million, respectively, for the three and nine months ended September 30, 2012 as compared to the same periods in 2011. The increase for the three and nine months ended September 30, 2012 was a result of increased Eagle Ford operations, which contributed to an increase of $7.5 million and $17.2 million, respectively, offset by a decline in costs of $1.2 million and $15.7 million, respectively, due to divestitures of dry gas properties.

Treating and Transportation. Treating and transportation expense increased $7.3 million and $23.5 million, respectively, for the three and nine months ended September 30, 2012 compared to the same periods in 2011. The increases were a result of increased daily production of 68% and 70%, respectively, in the Eagle Ford shale as well as higher unit costs required to transport incremental production from the area. Additionally, the Company accrued deficiency fees of $1.5 million and $4.2 million, respectively, related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements during the three and nine months ended September 30, 2012.

Production Taxes. Production taxes are highly correlated to commodity revenues, production volumes and commodity prices, which have impacted results for this expense item. Production taxes as a percentage of oil, NGL and natural gas sales were 3.6% and 2.9%, respectively, for the three and nine months ended September 30, 2012 compared to 2.0% and 2.2%, respectively, for the same periods in 2011. The increase in rates was primarily due to a higher percentage of our oil revenues being subject to taxation in the State of Texas.

Depreciation, Depletion and Amortization (DD&A). DD&A expense increased $15.8 million and $15.3 million, respectively, for the three and nine months ended September 30, 2012 compared to the same periods in 2011. The increase for the three months ended September 30, 2012 was due to a 45% increase in production and a higher DD&A rate driven by the impairment of our Southern Alberta Basin assets in the second quarter of 2012. The increase for the nine months ended September 30, 2012 was due to a 34% increase in production and the impact of our second quarter 2012 Southern Alberta Basin impairment, partially offset by a lower DD&A rate driven by significant additions of proved reserves, primarily in the Gates Ranch area.

General and Administrative Costs. General and administrative costs increased $10.5 million and $1.6 million, respectively, for the three and nine months ended September 30, 2012 as compared to the same periods in 2011. The increase for the three months ended September 30, 2012 was primarily due to a $7.3 million increase in stock-based compensation expense, driven by our higher stock price as compared to prior comparable periods partially offset by a lower number of PSUs outstanding in 2012. In addition, other general and administrative expenses increased $3.2 million due to a higher number of employees, contractors and consultants and higher office rent compared to the same period in 2011. The increase for the nine months ended September 30, 2012 was primarily due to a $4.9 million increase in other general and administrative expenses resulting from an increase in the number of employees, contractors and consultants and higher office rent compared to the same period in 2011. Such increases were partially offset by a decrease of $3.3 million in stock-based compensation expense, driven by our lower stock price as compared to prior comparable periods and a lower number of PSUs outstanding in 2012.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other income/expense, net, increased $0.7 million and $0.6 million, respectively, for the three and nine months ended September 30, 2012 compared to the same periods in 2011. The increase is primarily due to $0.2 million of fees incurred as a result of early prepayment of our Restated Term Loan in the third quarter of 2012, a decrease in interest capitalized primarily attributable to a lower unevaluated oil and gas property balance in the third quarter of 2012, and an increase in debt outstanding compared to prior comparable periods. The weighted average interest rate for the three and nine months ended September 30, 2012 was 6.52% and 7.65%, respectively, compared to 8.95% and 8.28%, respectively, for the same periods in 2011 due to a higher proportional mix of debt outstanding under the Credit Facility.

Provision for Income Taxes

The effective tax rate for the three and nine months ended September 30, 2012 was 35.5% and 36.1%, respectively, and the effective tax rate for the three and nine months ended September 30, 2011 was 35.8% and 35.0%, respectively. The provision for income taxes for the three and nine months ended September 30, 2012 differs from the tax computed at the federal statutory income tax rate primarily due to the impact of state income taxes and the non-deductibility of certain incentive compensation. As of September 30, 2012 and December 31, 2011, we had no unrecognized tax benefits and do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute of limitations within the next twelve months.

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2012, we had a net deferred tax asset of $19.8 million resulting primarily from net operating loss carryforwards and the difference between the book basis and tax basis of our oil and natural gas properties. Realization of the deferred tax asset is dependent, in part, on generating sufficient taxable income from the production of oil and natural gas properties prior to the expiration of loss carryforwards. We will continue to assess the need for a valuation allowance against deferred tax assets considering all available evidence obtained in future reporting periods.

Liquidity and Capital Resources

Our primary source of liquidity and capital is our operating cash flow. We also maintain our Credit Facility, which can be accessed as needed to supplement operating cash flow.

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil, NGLs and natural gas and the success of our development and exploration activities, as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to hedge the change in prices of a portion of our production, thereby mitigating our exposure to price declines, but these transactions may also limit our earnings potential in periods of rising commodity prices. The effects of these derivative transactions on our oil, NGL and natural gas sales are discussed above under Results of Operations Revenues. The majority of our capital expenditures is discretionary and could be curtailed if our cash flows materially decline from expected levels. Economic conditions and lower commodity prices could adversely affect our cash flow and liquidity. We will continue to monitor our cash flow and liquidity and, if appropriate, we may consider adjusting our capital expenditure program.

Senior Secured Revolving Credit Facility. On April 25, 2012, we entered into an amendment to our Credit Facility. Under this amendment, among other things, our borrowing base and commitments were increased from $325.0 million to $625.0 million and our capacity to hedge production was increased. Availability under the Credit Facility is restricted to the borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on our hedging arrangements, as well as asset divestitures. The amount of the borrowing base is affected by a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. Therefore, a significant reduction in capital spending could result in a reduced level of reserves that could cause a reduction in the borrowing base.

During the nine months ended September 30, 2012, we had net borrowings of $140.0 million under our Credit Facility. As of September 30, 2012, we had $170.0 million outstanding with $455.0 million of available borrowing capacity under the Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50%. Borrowings under the Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including a mortgage lien on oil and natural gas properties having at least 80% of the pre-tax SEC PV-10 reserve value, a guaranty by all of our domestic subsidiaries and a pledge of 100% of the membership and limited partnership interests of our domestic subsidiaries. Collateralized amounts under the mortgages are subject to semi-annual reviews based on updated reserve information. We are subject to certain financial covenants such as the requirement to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. As of September 30, 2012, our current ratio was 3.4 and our leverage ratio was 0.9. In addition, we are subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales and liens on properties. We were in compliance with all covenants as of September 30, 2012.

In October 2012, we borrowed and repaid an additional $20.0 million under the Credit Facility. After repayment, the available borrowing capacity was $455.0 million.

Second Lien Term Loan. Our Restated Term Loan of $20 million was prepaid in full on August 31, 2012. Outstanding fixed-rate borrowings under the Restated Term Loan bore interest at 13.75% and would have matured on October 2, 2012. The loan was collateralized by second priority liens on substantially all of our assets and upon prepayment, the second priority liens were released. In connection with the prepayment of the Restated Term Loan, $0.2 million of prepayment fees were incurred and have been reflected as a component of interest expense.

Senior Notes. On April 15, 2010, we issued and sold $200.0 million in aggregate principal amount of 9.500% Senior Notes due 2018 in a private offering. On September 21, 2010, we exchanged all of the privately placed Senior Notes for registered Senior Notes which contain terms substantially identical to the terms of the privately placed notes. The Senior Notes were issued under the Indenture with Wells Fargo Bank, National Association, as trustee. Provisions of the Indenture limit our ability to, among other things, incur additional indebtedness; pay dividends on our capital stock or purchase, repurchase, redeem, defease or retire capital stock or subordinated indebtedness; make investments; incur liens; create any consensual restriction on the ability of our restricted subsidiaries to pay dividends, make loans or transfer property to us; engage in transactions with affiliates; sell assets; and consolidate, merge or transfer assets. The Indenture also contains customary events of default. As of September 30, 2012, we were in compliance with the terms and provisions as contained within the Indenture. Interest is payable on the Senior Notes semi-annually on April 15 and October 15.

Cash Flows

The following table presents information regarding the change in our cash flow:

	Nine Months Ended September 30, 2012	2011
	(In thousands)	
Cash provided by (used in):		
Operating activities	$ 259,290	$ 201,770
Investing activities	(370,034)	(31,150)
Financing activities	112,871	(105,386)
Net increase in cash and cash equivalents	$ 2,127	$ 65,234

Operating Activities. Net cash provided by operating activities increased by $57.5 million for the nine months ended September 30, 2012 compared to the same period in 2011. The increase primarily reflects higher operating income in 2012 as a result of higher oil and NGL production.

Investing Activities. Net cash used in investing activities increased by $338.9 million for the nine months ended September 30, 2012 compared to the same period in 2011. The increase was primarily driven by higher capital spending related to our Eagle Ford drilling program and the receipt of lower proceeds from our Lobo and partial Olmos asset divestiture in 2012 as compared to our DJ Basin and Sacramento Basin asset divestitures in 2011.

Financing Activities. Net cash provided by financing activities increased by $218.3 million for the nine months ended September 30, 2012 compared to the same period in 2011. The increase was primarily related to net borrowings of $140.0 million under the Credit Facility in 2012 as compared to net repayments of $100.0 million in 2011.

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Capital Expenditures and Requirements

Our historical capital expenditures summary table is included in Items 1 and 2. Business and Properties in our 2011 Annual Report and is incorporated herein by reference.

Our capital expenditures for the nine months ended September 30, 2012 increased by $153.5 million to $492.5 million from $339.0 million for the nine months ended September 30, 2011. During the nine months ended September 30, 2012, we drilled 63 and completed 45 gross wells, the majority of which were located in the Eagle Ford shale. At current commodity prices, our positive operating cash flow, proceeds from asset divestitures and liquidity from the Credit Facility should be sufficient to fund planned capital expenditures for the remainder of 2012, which are projected to be approximately $660 to $680 million compared to our original $640 million budget.

We have the discretion to use availability under the Credit Facility and proceeds from divestitures to fund capital expenditures. We also have the ability to adjust our capital expenditure plans throughout the remainder of the year in response to market conditions.

Fair Value of Financial Instruments

The energy markets have historically been very volatile, and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps, costless collars and put options. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps, basis swaps, NYMEX roll swaps and costless collars for each year through 2015. Our fixed price swap, basis swap, NYMEX roll swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs and natural gas, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on expected production from existing wells at the inception of the derivative instruments. See Note 4 Commodity Derivative Contracts and Other Derivatives and Note 5 Fair Value Measurements included in Part I. Item 1. Financial Statements of this Form 10-Q for a listing of open contracts as of September 30, 2012, a description of the applicable accounting and the estimated fair market values as of September 30, 2012. The effects of material changes in market risk exposure associated with these derivative transactions are discussed below under Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Governmental Regulation

Except as noted below, there have been no material changes in governmental regulations from those previously disclosed in our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.

Derivative Transactions. On July 21, 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which, among other provisions, establishes federal oversight and regulation of the derivatives market and entities that participate in that market. The legislation requires the Commodities Futures Trading Commission (the CFTC) and the SEC to promulgate rules and regulations implementing the legislation. Some rules have been finalized, while other rules are still in the proposed or earlier stages. The effect of the rules and any additional regulations on our business is currently uncertain. Some transactions that the Company engages in have been classified as derivatives such as swaps and options and therefore become subject to the CFTC s jurisdiction and regulations. CFTC rules may require the Company to clear certain derivative instruments and comply with certain recordkeeping and reporting obligations. Additionally, the Company may be required to post margin for certain derivative instruments based on its credit support arrangements with its counterparties and may be unable to enter into certain transactions because of position limits imposed on physical commodities. Some of these obligations could begin as early as December 2012. The requirements to be enacted, to the extent applicable to us or our derivatives counterparties, may result in increased costs and cash collateral requirements for the types of derivative instruments we use to hedge and otherwise manage our financial and commercial risks related to fluctuations in oil, NGL and natural gas commodity prices. Any of the foregoing consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows. However at this time, we believe we will qualify for an end-user exemption relieving the Company from some or many of these requirements.

Air Emissions from Oil and Natural Gas Operations. On August 16, 2012 the U.S. Environmental Protection Agency (EPA) published their final rules that extend New Source Performance Standards (NSPS) and National Emission Standards for Hazardous Air Pollutants (NESHAPs) to certain exploration and production operations. The first compliance date was October 15, 2012 with a phase-in of some of the requirements over the next two years. The final rule requires the use of reduced emission completions or green completions on all hydraulically-fractured gas wells constructed or refractured after January 1, 2015. Only a portion of these new rules appear to affect our operations at this time by requiring new air emissions controls, equipment modification, maintenance, monitoring, recordkeeping and reporting. Although these new requirements will increase our operating and capital expenditures and it is possible that the EPA will adopt further regulation that could further increase our operating and capital expenditures, we do not currently expect such existing and new regulations will have a material negative impact on our operations or financial results.

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Critical Accounting Policies and Estimates

Management makes many estimates and assumptions in the application of generally accepted accounting principles that may have a material impact on our consolidated financial statements and related disclosures and on the comparability of such information over different reporting periods. All such estimates and assumptions affect reported amounts of assets, liabilities, revenues and expenses, as well as disclosures of contingent assets and liabilities. Estimates and assumptions are based on information available prior to the issuance of the financial statements. Changes in facts and circumstances or discovery of new information may result in revised estimates and actual results may differ from these estimates. There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2011 Annual Report, except as disclosed below.

Derivative Transactions and Activities

Effective January 1, 2012, we elected to de-designate all of our commodity contracts that were previously designated as cash flow hedges as of December 31, 2011 and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included $2.6 million ($1.6 million after tax) of unrealized gains, representing the mark-to-market value of our cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and are to be reclassified into earnings in future periods as the underlying hedged transactions affect earnings. During the three and nine months ended September 30, 2012, we reclassified unrealized net gains of $1.0 million ($0.6 million after tax) and $2.2 million ($1.4 million after tax), respectively, into earnings from Accumulated other comprehensive income. We expect to reclassify an additional $0.5 million ($0.3 million after tax) of unrealized net gains during the last three months of 2012 and $0.1 million of unrealized net losses during 2013 into earnings from Accumulated other comprehensive income. With the election to de-designate hedging instruments, all of our derivative instruments continue to be recorded at fair value with unrealized gains and losses recognized immediately in earnings within Revenues Derivative instruments on our Consolidated Statement of Operations, rather than in Accumulated other comprehensive income. Similar to our previous crude oil basis and NYMEX roll swap derivative instruments, these mark-to-market adjustments will produce a degree of earnings volatility that can be significant from period to period, but such adjustments will have no cash flow impact relative to changes in market prices. The cash flow impact occurs upon settlement of the underlying contract.

Recent Accounting Developments

For a discussion of recent accounting developments, see Note 2 Summary of Significant Accounting Policies included in Part I. Item 1. Financial Statements of this Form 10-Q.

Commitments and Contingencies

As is common within the oil and natural gas industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is management s belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows. See Note 9 Commitments and Contingencies included in Part I. Item 1. Financial Statements of this Form 10-Q.

We are party to various legal and regulatory proceedings arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk primarily related to adverse changes in oil, NGL and natural gas prices. We use derivative instruments to manage our commodity price risk caused by fluctuating prices. We do not enter into derivative instruments for trading purposes. For information regarding our exposure to certain market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2011 Annual Report and Note 4 Commodity Derivative Contracts and Other Derivatives included in Part I. Item 1. Financial Statements of this Form 10-Q.

As of September 30, 2012, we had open crude oil derivative contracts in a net asset position with a fair value of $2.5 million. A ten percent increase in crude oil prices would reduce the fair value by approximately $11.7 million, while a ten percent decrease in crude oil prices would increase the fair value by approximately $10.5 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

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As of September 30, 2012, we had open NGL derivative contracts in a net asset position with a fair value of $16.3 million. A ten percent increase in NGL prices would reduce the fair value by approximately $14.4 million, while a ten percent decrease in NGL prices would increase the fair value by approximately $14.4 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of September 30, 2012, we had open natural gas derivative contracts in a net asset position with a fair value of $1.8 million. A ten percent increase in natural gas prices would reduce the fair value by approximately $6.2 million, while a ten percent decrease in natural gas prices would increase the fair value by approximately $6.1 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

These transactions may expose us to the risk of loss in certain circumstances, including instances in which our production is less than expected, there is a widening of price differentials between delivery points for our production and the delivery point assumed in the derivative arrangement, or in the event of nonperformance under the contracts by the counterparties to our derivative agreements.

As of September 30, 2012, the Company s derivative instruments are with counterparties who are lenders under the Company s credit facilities or were lenders under the Company s credit facilities upon origination of the derivative instrument. This allows us to satisfy any need for margin obligations resulting from an adverse change in the fair market value of the derivative contracts with the collateral securing our credit facilities, thus eliminating the need for independent collateral postings. As of September 30, 2012, we had no deposits for collateral regarding commodity derivative instruments. Our derivative instrument assets and liabilities relate to commodity hedges that represent the difference between hedged prices and market prices on hedged volumes of the commodities as of September 30, 2012. We evaluated non-performance risk using the current credit default swap values for the counterparties and recorded a downward adjustment to the fair value of our derivative instruments in the amount of $0.1 million as of September 30, 2012.

We entered into oil, NGL and natural gas price derivative contracts with respect to a portion of our expected production through 2015. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices were to exceed the price established by the contract. As of September 30, 2012, 79% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 21% at Light Louisiana Sweet; 100% of the total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu, and 100% of total natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel.

We utilize counterparty and third party broker quotes to determine the valuation of our derivative instruments. Fair values derived from counterparties and brokers are further verified using relevant NYMEX futures contracts and exchange traded contracts, if deemed necessary, for each derivative settlement location. We have used this valuation technique since the adoption of the authoritative guidance for fair value measurements on January 1, 2008, and we have made no changes or adjustments to our technique since that date. We mark-to-market the fair values of our derivative instruments on a quarterly basis and 100% of our commodity derivative assets and liabilities are considered Level 3 instruments.

Item 4. Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of September 30, 2012. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2012, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to the Company s management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

We are party to various legal and regulatory proceedings arising in the ordinary course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, management does not believe any such matters will have a material adverse effect on our financial position, results of operations or cash flows.

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Item 1A. Risk Factors

There have been no material changes in our risk factors from those previously disclosed in Item 1A. of our 2011 Annual Report and our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.

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

Purchases of Equity Securities by the Issuer and Affiliated Purchasers for the three months ended September30, 2012:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
July 1 July 31	626	$ 35.50		
August 1 August 31	378	40.55		
September 1 September 30	456	42.51		
Total	1,460	$ 39.00		

(1) All of the shares were surrendered by our employees and directors to pay tax withholdings upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of common stock.

Issuance of Unregistered Securities

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

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Item 6. Exhibits

Exhibit Number	Description
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith

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SIGNATURES

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

ROSETTA RESOURCES INC.

By: /s/ John E. Hagale
John E. Hagale

Executive Vice President and Chief Financial Officer

(Duly Authorized Officer and Principal Financial Officer)

Date: November 7, 2012