Rosetta Resources Inc.
Form 10-Q
May 08, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **Quarterly Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
For The Quarterly Period Ended March 31, 2012

OR

¨ **Transition Report Pursuant To Section 13 or 15(d) of the Securities Exchange Act of 1934**
Commission File Number: 000-51801

ROSETTA RESOURCES INC.

(Exact name of registrant as specified in its charter)

Delaware	**43-2083519**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
717 Texas, Suite 2800, Houston, TX	**77002**
(Address of principal executive offices)	**(Zip Code)**

(Registrant s telephone number, including area code) (713) 335-4000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Securities Exchange Act of 1934.

Large accelerated filer x	Accelerated filer ¨
Non-Accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller Reporting Company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934). Yes ¨ No x

The number of shares of the registrant s Common Stock, $.001 par value per share, outstanding as of April 30, 2012 was 52,896,031.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Rosetta Resources Inc.

Consolidated Balance Sheet

(In thousands, except par value and share amounts)

	March 31, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 53,091	$ 47,050
Accounts receivable, net	68,056	77,374
Derivative instruments	10,691	10,171
Prepaid expenses	3,330	2,962
Current deferred tax asset	19,555	11,015
Other current assets	1,840	2,942
Total current assets	156,563	151,514
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	2,358,350	2,297,312
Unproved/unevaluated properties, not subject to amortization	137,228	141,016
Gas gathering systems and compressor stations	46,936	38,580
Other fixed assets	8,236	9,494
	2,550,750	2,486,402
Accumulated depreciation, depletion, and amortization, including impairment	(1,687,553)	(1,657,841)
Total property and equipment, net	863,197	828,561
Other assets:		
Deferred loan fees	8,099	8,575
Deferred tax asset	52,969	74,150
Derivative instruments	58	1,633
Other long-term assets	922	912
Total other assets	62,048	85,270
Total assets	$ 1,081,808	$ 1,065,345
Liabilities and Stockholders Equity		
Current liabilities:		
Accounts payable	$ 2,960	$ 2,489
Accrued liabilities	87,042	107,594
Royalties and other payables	50,705	50,689
Derivative instruments	16,286	6,788
Current portion of long-term debt	20,000	20,000
Total current liabilities	176,993	187,560

Long-term liabilities:		
Derivative instruments	8,837	1,351
Long-term debt	230,000	230,000
Other long-term liabilities	10,669	13,598
Total liabilities	426,499	432,509
Commitments and Contingencies (Note 9)		
Stockholders equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2012 or 2011		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 53,047,945 shares and 52,630,483 shares at March 31, 2012 and December 31, 2011, respectively	53	52
Additional paid-in capital	816,722	810,794
Treasury stock, at cost; 571,074 and 450,173 shares at March 31, 2012 and December 31, 2011, respectively	(16,996)	(11,296)
Accumulated other comprehensive income	1,579	1,632
Accumulated deficit	(146,049)	(168,346)
Total stockholders equity	655,309	632,836
Total liabilities and stockholders equity	$ 1,081,808	$ 1,065,345

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended March 31, 2012	2011
Revenues:		
Oil sales	$ 62,970	$ 28,749
NGL sales	43,760	18,542
Natural gas sales	23,689	49,780
Derivative instruments	(15,961)	
Total revenues	114,458	97,071
Operating costs and expenses:		
Lease operating expense	8,501	14,520
Treating and transportation	11,998	3,451
Production taxes	3,228	1,656
Depreciation, depletion, and amortization	32,899	34,029
General and administrative costs	17,291	21,070
Total operating costs and expenses	73,917	74,726
Operating income	40,541	22,345
Other expense (income):		
Interest expense, net of interest capitalized	5,461	6,346
Interest income	(2)	(28)
Other expense, net	113	273
Total other expense	5,572	6,591
Income before provision for income taxes	34,969	15,754
Income tax expense	12,672	4,757
Net income	$ 22,297	$ 10,997
Earnings per share:		
Basic	$ 0.43	$ 0.21
Diluted	$ 0.42	$ 0.21
Weighted average shares outstanding:		
Basic	52,399	51,854
Diluted	52,810	52,521

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Comprehensive Income

(In thousands)

(Unaudited)

	Three Months Ended March 31, 2012	2011
Net income	$ 22,297	$ 10,997
Other comprehensive income (loss):		
Change in fair value of derivative instruments		(29,722)
Reclassification of (gain) on settled derivative instruments		(8,631)
Tax provision related to cash flow derivative instruments	34	14,369
Amortization of accumulated other comprehensive gain related to de-designated hedges	(87)	
Other comprehensive income (loss)	(53)	(23,984)
Comprehensive income (loss)	$ 22,244	$ (12,987)

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Three Months Ended March 31, 2012	2011
Cash flows from operating activities:		
Net income	$ 22,297	$ 10,997
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	32,899	34,029
Deferred income taxes	12,672	5,842
Amortization of deferred loan fees recorded as interest expense	478	595
Stock-based compensation expense	5,423	10,590
Derivative instruments	17,952	(2,867)
Change in operating assets and liabilities:		
Accounts receivable	9,318	(5,706)
Prepaid expenses	(367)	(542)
Other current assets	296	167
Long-term assets	(10)	(20)
Accounts payable	471	1,021
Accrued liabilities	(27,655)	759
Royalties and other payables	16	(2,558)
Other long-term liabilities	(79)	(46)
Net cash provided by operating activities	73,711	52,261
Cash flows from investing activities:		
Additions to oil and gas assets	(127,981)	(70,741)
Disposals of oil and gas assets	65,624	60,953
Net cash used in investing activities	(62,357)	(9,788)
Cash flows from financing activities:		
Borrowings on Restated Revolver	50,000	
Payments on Restated Revolver	(50,000)	
Proceeds from stock options exercised	387	1,132
Purchases of treasury stock	(5,700)	(3,335)
Net cash used in financing activities	(5,313)	(2,203)
Net increase in cash	6,041	40,270
Cash and cash equivalents, beginning of period	47,050	41,634
Cash and cash equivalents, end of period	$ 53,091	$ 81,904
Supplemental disclosures:		
Capital expenditures included in accrued liabilities	$ 64,649	$ 40,181

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	Treasury Stock		Accumulated Other	Retained Earnings /	Total
	Shares	Amount	Paid-In Capital	Shares	Amount	Comprehensive (Loss)/Income	Accumulated Deficit	Stockholders Equity
Balance at December 31, 2011	52,630,483	$ 52	$ 810,794	450,173	$ (11,296)	$ 1,632	$ (168,346)	$ 632,836
Stock options exercised	34,712	1	387					388
Treasury stock employee tax payment				120,901	(5,700)			(5,700)
Stock-based compensation			5,541					5,541
Vesting of restricted stock	382,750							
Comprehensive income						(53)	22,297	22,244
Balance at March 31, 2012	53,047,945	$ 53	$ 816,722	571,074	$ (16,996)	$ 1,579	$ (146,049)	$ 655,309

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, and in the Southern Alberta Basin in Northwest Montana.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of only 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 United States of America. 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 April 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 U.S. generally accepted accounting principles (GAAP) and International Financial Reporting Standards (IFRS). In this guidance, the FASB clarifies that the concept of highest and best use and valuation premise in a fair value measurement is only relevant when measuring the fair value of nonfinancial assets and is not relevant when measuring the fair value of financial assets or liabilities. The FASB also addressed measuring the fair value of an instrument classified in shareholders equity whereby an entity should measure the fair value of its own equity instrument from the perspective of a market participant. In addition, this guidance requires disclosure of quantitative and qualitative information about unobservable inputs used in measuring the fair value of Level 3 instruments. The Company has 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 has adopted the provisions of this guidance, excluding the requirements deferred in the December 2011 guidance, effective January 1, 2012, 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:

	March 31, 2012	December 31, 2011
	(In thousands)	
Proved properties	$ 2,358,350	$ 2,297,312
Unproved/unevaluated properties	137,228	141,016
Gas gathering systems and compressor stations	46,936	38,580
Other fixed assets	8,236	9,494
Total property and equipment, gross	2,550,750	2,486,402
Less: Accumulated depreciation, depletion, and amortization, including impairment	(1,687,553)	(1,657,841)
Total property and equipment, net	$ 863,197	$ 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. On March 23, 2012, the Company closed the sale of properties for which consents for assignment, if required, were already received. Net proceeds, after adjusting for a January 1, 2012 effective date, were $65.6 million. The remaining portion of the transaction is anticipated to close in the second quarter of 2012. The agreement is subject to due diligence and post-closing purchase price adjustments. Proceeds from the initial closing of the divestiture were recorded as an adjustment 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 $2.0 million and $1.5 million of internal costs for the three months ended March 31, 2012 and 2011, respectively.

Oil and gas properties include costs of $137.2 million and $141.0 million as of March 31, 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. The decrease from December 31, 2011 to March 31, 2012 is the result of transferring certain exploratory costs into the full cost pool associated with evaluated properties in the Southern Alberta Basin and in the Eagle Ford shale.

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 March 31, 2012, which were based on a West Texas Intermediate oil price of $94.65 per Bbl and a Henry Hub natural gas price of $3.73 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 March 31, 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, 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.

As of March 31, 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:

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Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) In thousands)
Crude oil	2012	Costless Collar	7,600	2,090,000	$ 78.82	$ 114.91	$ (5,881)
Crude oil	2013	Costless Collar	6,750	2,463,750	79.44	117.29	(5,980)
Crude oil	2014	Costless Collar	2,000	730,000	82.50	111.95	(788)
				5,283,750			$ (12,649)

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) In thousands
Crude oil	May 2012 -December 2012	Basis Swap	2,500	612,500	$ 8.70	$	$ (4,062)
Crude oil	May 2012 - December 2012	NYMEX Roll Swap	2,500	612,500	(0.30)		38
Crude oil	2013	Basis Swap	1,875	684,375	5.80		(739)
Crude oil	2013	NYMEX Roll Swap	1,875	684,375	(0.18)		(394)
				2,593,750			$ (5,157)

Product	Settlement Period	Derivative Instrument	Notional Daily Volume Bbl	Total of Notional Volume Bbl	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl	Fair Market Value Asset/(Liability) In thousands)
NGL-Propane	2012	Swap	2,500	687,500	$ 53.22	$	$ 247
NGL-Isobutane	2012	Swap	760	209,000	71.70		(2,628)
NGL-Normal Butane	2012	Swap	780	214,500	67.86		(2,288)
NGL-Pentanes Plus	2012	Swap	660	181,500	89.77		(1,890)
NGL-Propane	2013	Swap	1,270	463,550	51.82		(1,108)
NGL-Isobutane	2013	Swap	380	138,700	72.59		(994)
NGL-Normal Butane	2013	Swap	420	153,300	70.57		(885)
NGL-Pentanes Plus	2013	Swap	430	156,950	88.75		(1,151)
NGL-Propane	2014	Swap	535	195,275	51.04		(325)
NGL-Isobutane	2014	Swap	155	56,575	71.82		(85)
NGL-Normal Butane	2014	Swap	165	60,225	70.47		(55)
NGL-Pentanes Plus	2014	Swap	145	52,925	89.22		(72)
				2,570,000			$ (11,234)

Product	Settlement Period	Derivative Instrument	Notional Daily Volume MMBtu	Total of Notional Volume MMBtu	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu	Fair Market Value Asset/(Liability) In thousands)
Natural gas	2012	Costless Collar	20,000	5,500,000	$ 5.13	$ 6.31	$ 14,666
				5,500,000			$ 14,666

As of March 31, 2012, the Company s derivative instruments are with counterparties who are lenders under the Company s credit facilities. 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. As of March 31, 2012, the Company had no deposits for collateral regarding its commodity derivative positions.

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The following table sets forth the results of derivative settlements for the respective periods as reflected in the Consolidated Statement of Operations:

	Three Months Ended March 31,			
	2012		2011	
Crude Oil				
Quantity settled (Bbl)		631,600		24,800
Decrease in Oil sales revenue (In thousands)(1)	$		$	(321)
Realized (loss) in Derivative instruments (In thousands)(2)		(109)		
NGL				
Quantity settled (Bbl)		427,700		63,000
Decrease in NGL sales revenue (In thousands)(1)	$		$	(1,186)
Realized (loss) in Derivative instruments (In thousands)(2)		(2,395)		
Natural Gas				
Quantity settled (MMBtu)		1,820,000		4,500,000
Increase in Natural gas sales revenue (In thousands)(1)(3)	$		$	7,271
Realized gain in Derivative instruments (In thousands)(2)		4,495		

(1) For the three months ended March 31, 2011, amount represents the realized hedge gains/(losses) reclassified from Accumulated other comprehensive income into the respective commodity Revenue line item for derivatives designated as hedging instruments.

(2) For the three months ended March 31, 2012, amount represents the realized derivative gains/(losses) and the recognition of realized gains/(losses) reclassified from Accumulated other comprehensive income resulting from the Company s discontinuance of hedge accounting effective January 1, 2012.

(3) For the three months ended March 31, 2011, amount excludes approximately $2.9 million of realized gains associated with the termination of derivatives in 2011 used to hedge production from the Company s DJ Basin properties, which were divested in March 2011.

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 marked-to-market value of the Company s cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the marked-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and will be reclassified into earnings in future periods as the underlying hedged transactions affect earnings. The Company expects to reclassify into earnings $2.7 million of unrealized net gains during 2012 and $0.1 million of unrealized net losses during 2013 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 marked-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 impact to cash flow occurs upon settlement of the underlying contract.

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 March 31, 2012 and December 31, 2011, respectively:

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Fair Values of Derivative Instruments

	Location on Consolidated Balance Sheet	Assets (Liabilities) (In thousands) Fair Value March 31, 2012	December 31, 2011
Commodity derivative contracts			
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 - non-current assets		
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
Commodity derivative contracts			
Oil	Derivative instruments - current assets	$ (3,495)	$
Oil	Derivative instruments - non-current assets		379
Oil	Derivative instruments - current liabilities	(8,837)	855
Oil	Derivative instruments - long-term liabilities	(5,474)	
NGL	Derivative instruments - current assets	(480)	
NGL	Derivative instruments - non-current assets	58	
NGL	Derivative instruments - current liabilities	(7,449)	
NGL	Derivative instruments - long-term liabilities	(3,363)	
Natural gas	Derivative instruments - current assets	14,666	
	Total derivatives not designated as hedging instruments	$ (14,374)	$ 1,234
	Total derivatives	$ (14,374)	$ 3,665

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 months ended March 31, 2012.

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 months ended March 31, 2012 and 2011, respectively:

	Location on Consolidated Statement of Operations	Three Months Ended March 31, 2012	2011(1)
Hedge gain (loss) reclassified from Accumulated OCI into income	Oil sales	$	$ (321)
	NGL sales		(1,186)
	Natural gas sales		7,271
	Derivative instruments	87	
		$ 87	$ 5,764

	Location on Consolidated Statement of Operations	Three Months Ended March 31, 2012	2011(1)
Realized and unrealized gain (loss) recognized in income	Natural gas sales	$	$ 2,867
	Derivative instruments	(16,048)	
		$ (16,048)	$ 2,867

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

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(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 or 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.

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 and their placement within the fair value hierarchy levels.

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 March 31, 2012			
	Level 1	**Level 2**	**Level 3**	**Total**
	(In thousands)			
Assets (liabilities):				
Money market funds	$	$ 1,035	$	$ 1,035
Commodity derivative contracts			(14,374)	(14,374)
Total	$	$ 1,035	$ (14,374)	$ (13,339)

	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

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

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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 March 31, 2012:

Level 3 Instrument	Fair Value as of March 31, 2012 Asset (Liability)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Range Weighted Average	Per Unit
Oil NYMEX roll swap	$ 38	Discounted cash flow	Forward price curve - NYMEX roll swaps	$ (0.20)	$ 0.38	$ 0.06	Bbl
Oil NYMEX roll swap	(394)	Discounted cash flow	Forward price curve - NYMEX roll swaps	(0.84)	(0.23)	(0.59)	Bbl
Oil basis swaps	(4,801)	Discounted cash flow	Forward price curve - basis swaps	4.35	22.37	3.73	Bbl
Oil costless collars	(12,649)	Option model	Forward price curve - costless collar option value	(11.28)	9.28	(2.43)	Bbl
NGL swap propane	$ 247	Discounted cash flow	Forward price curve - swaps	$ 51.66	$ 54.39	$ 0.36	Bbl
NGL swaps	(11,481)	Discounted cash flow	Forward price curve - swaps	51.50	100.43	(6.17)	Bbl
Natural gas costless collar	$ 14,666	Option model	Forward price curve - costless collar option value	$ (0.02)	$ 3.68	$ 1.35	MMBtu

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 current credit default swap values and default probabilities for the Company and its counterparties in determining fair value and recorded a downward adjustment to the fair value of its derivative instruments in the amount of $0.2 million as of March 31, 2012.

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) (In thousands)	Total
Balance at January 1, 2012	$ 3,665	$ 1,035	$ 4,700
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	(16,048)		(16,048)
Included in Other Comprehensive Income			
Purchases, Issuances and Settlements			
Settlements	(1,991)		(1,991)
Purchases			
Transfers out of Level 3		(1,035)	(1,035)
Balance at March 31, 2012	$ (14,374)	$	$ (14,374)

	Derivatives Asset (Liability)	Money Market Funds Asset (Liability) (In thousands)	Total
Balance at January 1, 2011	$ 19,657	$ 1,035	$ 20,692
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings (1)	(424)		(424)
Included in Other Comprehensive Income	(29,722)		(29,722)
Purchases, Issuances and Settlements			
Settlements	(8,631)		(8,631)

Purchases	2,867			2,867
Transfers in and out of Level 3				
Balance at March 31, 2011	$ (16,253)	$	1,035	$ (15,218)

(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 at the end of the reporting period.

(2) No gains or losses were included in earnings attributable to the change in unrealized gains or losses relating to financial assets and liabilities still held at the end of the period.

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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 March 31, 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, borrowings under the Restated Revolver and fixed rate borrowings outstanding under the Second Lien Term Loan. The fair value of the Company s publicly traded Senior Notes is based upon an unadjusted quoted market price and is considered a Level 1 instrument. The Company s borrowings under the Restated Revolver approximate fair value as the interest rates are variable and reflective of market rates, which results in a Level 1 instrument. The fair value of the Company s borrowings under the Second Lien Term Loan is estimated using a discounted cash flow technique that incorporates a market interest yield curve with adjustments for duration, optionality and risk profile, which results in a Level 2 instrument. As of March 31, 2012, the carrying amount and estimated fair value of total debt was $250.0 million and $271.3 million, respectively.

(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:

		Three Months Ended March 31, 2012 (In thousands)
ARO as of December 31, 2011	$	14,313
Liabilities incurred during period		21
Liabilities settled during period		(3,198)
Revision of previous estimates		
Accretion expense		285
ARO as of March 31, 2012	$	11,421

As of March 31, 2012, the $1.6 million current portion of the total ARO is included in Accrued liabilities, and the $9.8 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 May 10, 2011, the Company entered into an amendment to its Amended and Restated Senior Revolving Credit Agreement (the Restated Revolver). Under this amendment, among other things, the Company s senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver 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 March 31, 2012, the Company had $30.0 million outstanding with $295.0 million of available borrowing capacity under its Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. The weighted average borrowing rate for the three months ended March 31, 2012 under the Restated Revolver was 2.03%. Borrowings under the Restated Revolver 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 the financial covenants as defined in the credit agreement. The terms of the agreement require the maintenance of 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 March 31, 2012, the Company s current ratio was 3.2 and the leverage ratio was 0.8. 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. The Company was in compliance with all covenants as of March 31, 2012.

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The Company s semi-annual borrowing base review was completed on April 25, 2012 and the borrowing base was increased from $325.0 million to $625.0 million.

Second Lien Term Loan. The Company s amended and restated term loan (the Restated Term Loan) matures on October 2, 2012. As of March 31, 2012, the Company had $20.0 million of fixed rate borrowings outstanding bearing interest at 13.75% under the Restated Term Loan. The Company has the right to prepay the fixed rate borrowings outstanding under the Restated Term Loan with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of the Company s assets. The Company is subject to the financial covenants as defined in the term loan agreement. The Company is required under the term loan agreement to maintain a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter. The terms of the agreement also require the Company to maintain 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. As of March 31, 2012, the Company s reserve coverage ratio was 2.6 and the leverage ratio was 0.8. In addition, the Company is subject to covenants, including limitations on dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales and liens on properties. The Company was in compliance with all covenants as of March 31, 2012.

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, 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 March 31, 2012, the Company had total outstanding borrowings of $250.0 million. For the three months ended March 31, 2012, the Company s weighted average borrowing rate was 8.25%.

(8) Income Taxes

The Company s effective tax rate for the three months ended March 31, 2012 and 2011 was 36.2% and 30.2%, respectively. The provision for income taxes for the three months ended March 31, 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 March 31, 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 March 31, 2012, the Company had a net deferred tax asset of $72.5 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 Commitments. The Company has various production volume transportation 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 417 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 March 31, 2012, the Company has

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accrued deficiency fees of $1.2 million and expects to continue to accrue additional deficiency fees until resources are more fully developed to increase production to fulfill the delivery commitments. Future obligations under firm oil and natural gas transportation agreements as of March 31, 2012 are as follows:

	March 31, 2012 (In thousands)
2012	$ 8,751
2013	28,530
2014	33,717
2015	33,717
2016	33,809
Thereafter	165,689
	$ 304,213

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors primarily to execute our Eagle Ford shale and Southern Alberta Basin drilling programs. As of March 31, 2012, the Company had no outstanding drilling commitments with terms greater than one year and future obligations through December 31, 2012 totaled $11.8 million.

The Company has agreements with completion service contractors for the stimulation, cementing and delivery of drilling fluids to support current operations. As of March 31, 2012, the minimum contractual commitments for these agreements totaled $10.8 million. Payments under these agreements are accounted for as capital additions to our oil and gas properties.

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 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 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 March 31,	
	2012	2011
	(In thousands)	
Basic weighted average number of shares outstanding	52,399	51,854
Dilution effect of stock option and awards at the end of the period	411	667
Diluted weighted average number of shares outstanding	52,810	52,521
Anti-dilutive stock awards and shares	1	27

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(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 March 31, 2012	Three Months Ended March 31, 2011
	(in thousands)	
Total stock-based compensation expense	$ 5,585	$ 10,731
Capitalized in oil and gas properties	(162)	(141)
Net stock-based compensation expense	$ 5,423	$ 10,590

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 months ended March 31, 2012, the Company recorded compensation expense of approximately $1.4 million related to these equity awards. As of March 31, 2012, unrecognized stock-based compensation expense related to unvested restricted stock was approximately $7.4 million.

Stock-based compensation expense associated with the PSUs granted to executive management is recognized over a three-year vesting period when certain conditions have been met. On December 31, 2011, the performance period ended for the 2009 PSUs and the units were settled in a mixture of cash and common stock in the first quarter of 2012. The portion of PSUs settled in common stock resulted in an additional $0.7 million of stock-based compensation expense based upon the common stock value at the February 2012 settlement date.

For the three months ended March 31, 2012, the Company recognized compensation expense of $2.8 million associated with the 2010 PSUs, $0.5 million associated with the 2011 PSUs and $0.2 million associated with the 2012 PSUs.

At the current fair value as of March 31, 2012 and assuming that the Board elects the maximum available payout of 200% for all PSU metrics, total stock-based compensation expense related to the PSUs to be recognized over the three-year service periods would be $14.9 million, $7.3 million and $5.9 million, respectively, for the 2010, 2011 and 2012 PSU plans. The Company s total stock-based compensation expense will be measured and adjusted quarterly until settlement occurs, based on the Company s quarter-end closing common stock prices and Monte Carlo model valuations. For a more detailed description of the Company s PSU plans, 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.

(13) Subsequent Events

On April 25, 2012, the Company s semi-annual borrowing base review was completed and the borrowing base under the Restated Revolver was increased from $325.0 million to $625.0 million.

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, expect, plan, project, intend, anticipate, believe, 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 Inc. and its subsidiaries.

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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, 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;
- reserve levels;
- 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;

potential reserve revisions;

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, environmental regulations and environmental 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;

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 months ended March 31, 2012 compared to the three months ended March 31, 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.

The following summarizes our performance for the three months ended March 31, 2012 as compared to the same period for 2011:

production increased 32% to 3.1 MMBoe for the three months ended March 31, 2012 from 2.3 MMBoe for the three months ended March 31, 2011;

15 gross (15 net) wells were drilled with a net success rate of 100% for the three months ended March 31, 2012 compared to 11 gross (11 net) wells drilled with a net success rate of 100% for the same period in 2011;

average realized oil prices, including realized derivative losses, increased 10% to $92.81 per Bbl for the three months ended March 31, 2012 from $84.68 per Bbl for the three months ended March 31, 2011;

average realized NGL prices, including realized derivative losses, increased 3% to $45.49 per Bbl for the three months ended March 31, 2012 from $44.02 per Bbl for the three months ended March 31, 2011;

average realized natural gas prices, including realized derivative gains, decreased 41% to $3.13 per Mcf for the three months ended March 31, 2012 from $5.30 per Mcf for the three months ended March 31, 2011;

total revenues, including net realized and unrealized derivative gains and losses, increased $17.4 million, or 18%, to $114.5 million for the three months ended March 31, 2012 from $97.1 million for the three months ended March 31, 2011;

lease operating expense decreased 56% to $2.76 per Boe for the three months ended March 31, 2012 from $6.24 per Boe for the three months ended March 31, 2011;

depreciation, depletion and amortization expense decreased 27% to $10.69 per Boe for the three months ended March 31, 2012 from $14.63 per Boe for the three months ended March 31, 2011;

general and administrative expense decreased 38% to $5.62 per Boe for the three months ended March 31, 2012 from $9.06 per Boe for the three months ended March 31, 2011; and

diluted earnings per share increased $0.21 to $0.42 for the three months ended March 31, 2012 from $0.21 for the three months ended March 31, 2011.

We continue to build upon our success as an unconventional resource player with the development of our assets in the Eagle Ford shale in South Texas, one of the most active energy plays in the United States. Our success in the area resulted in double-digit increases in production and a doubling of total proved reserves in 2011. These assets are also contributing to an overall decrease in our total cost structure and a more balanced commodity production mix, with oil and NGLs accounting for approximately half of our first quarter 2012 production.

The Eagle Ford shale is our largest producing area, representing approximately 90% of our total production for the quarter ended March 31, 2012. We were an early entrant into the region, accumulating a significant leasehold position in this highly-competitive play during 2008 and 2009. Overall, we hold 65,000 net acres with roughly 50,000 located in the liquids-rich area of the play. During 2011, our primary focus was the development of our 26,500-acre Gates Ranch acreage in Webb County where well results greatly exceeded our original expectations and led to two upward revisions of gross estimated ultimate recovery from the area. In addition, well density was increased to 65-acre spacing from the past practice of 100-acre spacing to potentially enhance the recovery of hydrocarbons from the area. We also positively tested and began development of four new Eagle Ford shale areas across 13,600 net acres in the liquids-rich area outside of Gates Ranch. This newly delineated leasehold expands our already strong liquids-rich position. The majority of the remaining 10,000 acres is scheduled for testing during 2012.

The success of our Eagle Ford drilling program was the basis for a significant increase in reserve estimates during 2011. At year-end, our estimated proved reserves were 161 MMBoe (965 Bcfe), a 101% increase from our estimate of 80 MMBoe (479 Bcfe) as of December 31, 2010. Approximately 57% of our reserves discovered in the Eagle Ford shale are liquids, shifting our production portfolio to greater levels of higher-valued oil and NGLs. For the quarter ended March 31, 2012, more than 51% of our production was from oil and NGLs as compared to 33% for the same period a year ago. Through cost control measures and the divestiture of certain non-strategic assets, our lease operating expenses have decreased to $2.76 per Boe for the first quarter of 2012 from $6.24 per Boe for the same period in 2011.

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We successfully drilled 15 and completed 12 Eagle Ford wells during the quarter ended March 31, 2012. As of that date, we had completed a total of 75 wells in the Eagle Ford shale. Less than 10 percent of our identified Eagle Ford inventory is drilled and on production.

With the growth of our shale activities, we have streamlined our operations by divesting 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 quarter of 2012, we entered into an agreement to sell our Lobo assets and part of our Olmos assets in South Texas for $95 million, subject to customary closing adjustments and the receipt of required consents for assignment. On March 23, 2012, we closed the sale of properties for which consents for assignment, if required, were already received. Net proceeds, after adjusting for a January 1, 2012 effective date, were $65.6 million. The remaining portion of the transaction is anticipated to close in the second quarter of 2012. We utilized $50.0 million of the divestiture net proceeds from the transaction to repay debt drawn during the quarter under the Restated Revolver.

Another shale focus area lies in the Southern Alberta Basin in Northwest Montana. We control approximately 300,000 net acres in the exploration play to test the economic potential in the Banff, Bakken and Three Forks reservoirs. In late 2009, we began an eleven-well vertical drilling program that was completed during the second quarter of 2011. The results from that initiative contributed to the design of a seven-well horizontal drilling program that is currently underway. As of March 31, 2012, four wells have been drilled with the remaining three wells expected to be drilled in the second quarter of 2012 utilizing modified completion techniques aimed at achieving better isolation in the target zones. Evaluations of the initial drilling results confirm the complexity of the play and the need for continued assessment of the area by us and the industry.

Our business goals for 2012 are based on an announced capital program of $640.0 million with more than 90% allocated to the evaluation and development of our Eagle Ford assets, which are expected to deliver significant year-over-year production growth. Our plans for the year are based on a four to five rig program in the Eagle Ford shale and the completion of 55 to 60 new wells in both the Gates Ranch area and other liquids areas of the play. Based on current development plans, market conditions and our understanding of the play, we expect the Eagle Ford shale program to be self-funding by the end of 2012. Approximately 5% of the capital funds will be spent for continued evaluation of the Southern Alberta Basin. In addition to our focus in the Eagle Ford shale area, we are also evaluating new opportunities to drive the long-term growth and sustainability of the Company. We will continue to evaluate other unconventional resources that offer a viable inventory of projects. These opportunities are expected to be a blend of new higher-risk exploration as well as producing property acquisitions.

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. Our business model takes into account the threats that could impede achievement of our stated growth objectives and the building of our asset base. However, we cannot completely control all external factors that could affect our operating environment. 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 the majority of our production located in the Eagle Ford shale, we have taken aggressive steps to ensure 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 revolving credit facility and the proceeds from our recent asset divestiture. We monitor our liquidity continuously and 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.

The semi-annual borrowing base redetermination was recently completed for our Restated Revolver, and effective April 25, 2012, the borrowing base was increased from $325 million to $625 million. We also utilized $50.0 million of the net proceeds from the divestiture of our Lobo and Olmos assets to repay debt drawn during the quarter under the Restated Revolver. Availability under the Restated Revolver 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 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. As of May 1, 2012, we had $30.0 million outstanding with $595 million available for borrowing under the Restated Revolver.

Results of Operations

Revenues

Our consolidated financial statements reflect total revenue of $114.5 million based on total volumes of 3.1 MMBoe and net derivative losses of $16.0 million for the first quarter of 2012.

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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 prices:

	Three Months Ended March 31,		
	2012	2011	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)		
Revenue:			
Oil sales	$ 62,970	$ 28,749	119%
NGL sales	43,760	18,542	136%
Natural gas sales	23,689	49,780	(52%)
Derivative instruments	(15,961)		(100%)
Total revenue	$ 114,458	$ 97,071	18%
Production:			
Oil (MBbls)	677.3	339.5	99%
NGLs (MBbls)	909.4	421.2	116%
Natural gas (Bcf)	9.0	9.4	(4%)
Total equivalents (MBoe)	3,078.4	2,326.7	32%
Average sales price:			
Oil, excluding derivatives (per Bbl)	$ 92.97	$ 85.63	9%
Oil, including realized derivatives (per Bbl)(1)	92.81	84.68	10%
NGL, excluding derivatives (per Bbl)	48.12	46.84	3%
NGL, including realized derivatives (per Bbl)(1)	45.49	44.02	3%
Natural gas, excluding derivatives (per Mcf)	2.63	4.22	(38%)
Natural gas, including realized derivatives (per Mcf)(1)	3.13	5.30	(41%)
Revenue, including realized derivatives (per Boe)(1)	43.01	41.72	3%

(1) Adjusted for derivative realized gains (losses), which for the three months ended March 31, 2012 included realized derivatives losses of $0.1 million and $2.4 million for oil and NGLs, respectively, and a realized derivative gain of $4.5 million for natural gas. For the three months ended March 31, 2011, included realized derivatives losses of $0.3 million and $1.2 million for oil and NGLs, respectively, and a realized derivative gain of $10.1 million for natural gas.

Oil. For the three months ended March 31, 2012, oil revenues, including realized derivative losses, increased by $34.1 million from the same period in 2011. The increase was attributable to an increase in production of 337.8 MBbls for the three months ended March 31, 2012 from the same period in 2011 due to newly completed wells in the Eagle Ford shale that flowed to sales. In addition to the increase in crude oil production, the average realized price, including the effects of realized derivative losses, increased by $8.13 per Bbl for the three months ended March 31, 2012 from the same period in 2011. Realized derivative losses of $0.1 million for the three months ended March 31, 2012 are reported as a component of Derivative instruments within Revenues. For the three months ended March 31, 2011, the effect of oil hedging activities on oil revenue resulted in a loss of $0.3 million and is reported as a component of Oil sales within Revenues.

NGLs. For the three months ended March 31, 2012, NGL revenues, including realized derivative losses, increased by $22.8 million from the same period in 2011. The increase was attributable to an increase in production of 488.2 MBbls for the three months ended March 31, 2012 from the same period in 2011 due to newly completed wells in the Eagle Ford shale that flowed to sales. In addition to the increase in NGL production, the average realized price, including the effects of realized derivative losses, increased by $1.47 per Bbl for the three months ended March 31, 2012 from the same period in 2011. Realized derivative losses of $2.4 million for the three months ended March 31, 2012 are reported as a component of Derivative instruments within Revenues. For the three months ended March 31, 2011, the effect of NGL hedging activities on NGL revenue resulted in a loss of $1.2 million and is reported as a component of NGL sales within Revenues.

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Natural Gas. For the three months ended March 31, 2012, natural gas revenues, including realized derivative gains, decreased by $21.6 million from the same period in 2011. The decrease was primarily due to a $2.17 per Mcf decline in the average realized price, including the effects of realized derivative gains, and also due to a 4% decline in natural gas production for the three months ended March 31, 2012 from the same period in 2011. Realized derivative gains of $4.5 million for the three months ended March 31, 2012 are reported as a component of Derivative instruments within Revenues. For the three months ended March 31, 2011, the effect of natural gas hedging activities on natural gas revenues resulted in a gain of $10.1 million and is reported as a component of Natural gas sales within Revenues.

Derivative Instruments. For the three months ended March 31, 2012, Derivative instruments include an unrealized derivative loss of $18.0 million due to changes in fair value on commodity derivative contracts, a realized derivative gain of $0.1 million due to the reclassification of commodity hedging gains from Accumulated other comprehensive income, and a realized derivative gain of $1.9 million from derivative settlements. These realized derivative gains represent cash settlements associated with our commodity derivative contracts. For the three months ended March 31, 2011, realized derivative gains of $8.6 million reflecting cash settlements on derivative contracts designated as hedging instruments were reported as a component of Oil, NGL and Natural gas sales within Revenues.

Operating Expenses

The following table presents information regarding our operating expenses:

	Three Months Ended March 31,		
	2012	2011	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)		
Lease operating expense	$ 8,501	$ 14,520	(41%)
Treating and transportation	11,998	3,451	248%
Production taxes	3,228	1,656	95%
Depreciation, depletion and amortization (DD&A)	32,899	34,029	(3%)
General and administrative costs	17,291	21,070	(18%)
Costs and expenses (per Boe of production)			
Lease operating expense	$ 2.76	$ 6.24	(56%)
Treating and transportation	3.90	1.48	164%
Production taxes	1.05	0.71	48%
Depreciation, depletion and amortization (DD&A)	10.69	14.63	(27%)
General and administrative costs	5.62	9.06	(38%)
General and administrative costs, excluding stock-based compensation	3.86	4.50	(14%)
Production costs (1)	12.63	19.41	(35%)

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

Lease Operating Expense. Lease operating expense decreased $6.0 million for the three months ended March 31, 2012 compared to the same period in 2011. The decrease was primarily attributable to the divestiture of properties and suspension of drilling programs in areas that produce primarily from dry gas reservoirs, which contributed to a decline in direct lease operating expense, ad valorem taxes and workover expenses of $5.9 million, $3.7 million and $0.4 million, respectively, for the three months ended March 31, 2012 compared to the same period in 2011. The decrease for the three months ended March 31, 2012 was partially offset by increases in direct lease operating expense and ad valorem taxes of $1.1 million and $2.9 million, respectively, related to our Eagle Ford operations.

Treating and Transportation. Treating and transportation expense increased $8.5 million for the three months ended March 31, 2012 compared to the same period in 2011. The increase was a result of increased production in the Eagle Ford shale and accrued deficiency fees of $1.2 million related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements during the three months ended March 31, 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 2.5% for the three months ended

March 31, 2012 compared to 1.9% for the same period in 2011. The increase in rate was primarily the result of a 104% increase in oil production in the State of Texas.

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Depreciation, Depletion and Amortization (DD&A). DD&A expense decreased $1.1 million for the three months ended March 31, 2012 compared to the same period in 2011. The decrease in 2012 was partially due to a lower DD&A rate driven by significant additions of proved reserves, primarily in the Gates Ranch area, in the second quarter of 2011. The remainder of the decrease in DD&A was due to lower accretion and depreciation expense associated with facilities, ARO obligations and other fixed assets that were divested in 2011.

General and Administrative Costs. General and administrative costs decreased $3.8 million for the three months ended March 31, 2012 from the same period in 2011. The decrease was primarily due to a $5.2 million decrease in stock-based compensation expense primarily as a result of the settlement of certain performance share units. The decrease was partially offset by a $0.4 million increase in salaries, wages, benefits and bonuses, a $0.5 million increase in contractor expenses and a $0.5 million increase in other general and administrative expenses.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other income/expense, net, decreased $1.0 million for the three months ended March 31, 2012 compared to the same period in 2011.

For the three months ended March 31, 2012, the decrease in Total other expense was primarily due to our repayment of $100.0 million under the Restated Revolver in April 2011 resulting in lower gross interest expense, and an increase in capitalized interest resulting from a higher weighted average interest rate. The weighted average interest rate for the three months ended March 31, 2012 was 8.25% compared to 7.10% for the same period in 2011 due to a higher proportional mix of debt outstanding under the Restated Term Loan and Senior Notes.

Provision for Income Taxes

The effective tax rate for the three months ended March 31, 2012 and 2011 was 36.2% and 30.2%, respectively. The provision for income taxes for the three months ended March 31, 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 March 31, 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 March 31, 2012, we had a net deferred tax asset of $72.5 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 and cash on hand. We also maintain a revolving line of credit, 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 are discretionary and could be curtailed if our cash flows 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 May 10, 2011, we entered into an amendment to our Restated Revolver. Under this amendment, among other things, our senior secured revolving line of credit was increased from $600.0 million to $750.0 million and the term of the Restated Revolver was extended from July 1, 2012 to May 10, 2016. Availability under the Restated Revolver 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.

We utilized $50.0 million of the divestiture net proceeds from the Lobo and Olmos transaction to repay debt drawn during the quarter under the Restated Revolver. As of March 31, 2012, we had $30.0 million outstanding with $295.0 million of available borrowing capacity under the Restated Revolver. Amounts outstanding under the Restated Revolver bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.75% to 2.75%. Borrowings under the Restated Revolver 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 the financial covenants as defined in the credit agreement. The terms of the agreement require the maintenance of 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 March 31, 2012, our current ratio was 3.2 and our leverage ratio was 0.8. 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 March 31, 2012.

Our semi-annual borrowing base review was completed on April 25, 2012 and the borrowing base was increased from $325.0 million to $625.0 million.

Second Lien Term Loan. Our Restated Term Loan matures on October 2, 2012. As of March 31, 2012, we had $20.0 million of fixed rate borrowings outstanding under the Restated Term Loan bearing interest at 13.75%. We have the right to prepay the fixed rate borrowings outstanding with a make-whole amount at a discount factor equal to 1% plus the U.S. Treasury yield security having a maturity closest to the remaining life of the loan. The loan is collateralized by second priority liens on substantially all of our assets. We are also subject to certain financial covenants, including the requirement to maintain (i) a minimum reserve ratio of total reserve value to total debt of not less than 1.5 to 1.0 as of the end of each fiscal quarter and (ii) 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. As of March 31, 2012, our reserve coverage ratio was 2.6 and our leverage ratio was 0.8. In addition, we are subject to covenants, including limitations on 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 March 31, 2012.

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. 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 March 31, 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. 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.

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Cash Flows

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

	Three Months Ended March 31, 2012	2011
	(In thousands)	
Cash flows provided by operating activities	$ 73,711	$ 52,261
Cash flows used in investing activities	(62,357)	(9,788)
Cash flows used in financing activities	(5,313)	(2,203)
Net increase in cash and cash equivalents	$ 6,041	$ 40,270

Operating Activities. Key drivers of net cash provided by operating activities are commodity prices, production volumes and costs and expenses, which primarily include operating costs, taxes other than income taxes, transportation, interest expense and general and administrative expenses. Net cash provided by operating activities continues to be a primary source of liquidity and capital used to finance our capital program.

Cash flows provided by operating activities increased by $21.5 million for the three months ended March 31, 2012 compared to the same period in 2011. This increase was primarily due to higher oil and NGL prices and increased oil and NGL production during the three months ended March 31, 2012 compared to the same period in 2011.

Investing Activities. The primary driver of cash used in investing activities is capital spending, net of divestiture proceeds.

Cash flows used in investing activities increased by $52.6 million for the three months ended March 31, 2012 compared to the same period in 2011. The net increase was primarily driven by capital spending in which we drilled 15 and completed 12 gross wells as compared to the drilling and completion of 11 and 9 gross wells, respectively, during the same period in 2011 partially offset by the receipt of divestiture proceeds.

Financing Activities. The primary drivers of cash used in financing activities are repayments and borrowings on our debt facilities, equity transactions associated with the exercise of stock options and the acquisition of treasury shares from employees and directors to pay tax withholdings upon the vesting of restricted stock.

Cash flows used in financing activities increased by $3.1 million for the three months ended March 31, 2012 compared to the same period in 2011. The increase is primarily related to the purchases of treasury shares during the current period.

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 three months ended March 31, 2012 increased by $44.6 million to $132.7 million from $88.1 million for the three months ended March 31, 2011. During the three months ended March 31, 2012, we drilled 15 and completed 12 gross wells, all 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 Restated Revolver should be sufficient to fund planned capital expenditures for 2012, which are projected to be approximately $640 million. Our planned capital expenditures primarily reflect development drilling in the Eagle Ford.

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

Commodity Price Risk and Related Derivative Activities

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 2014. 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.

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The following table sets forth the results of commodity derivative settlements:

	Three Months Ended March 31,	
	2012	**2011**
Crude Oil		
Quantity settled (Bbl)	631,600	24,800
Decrease in Oil sales revenue (In thousands)(1)	$	$ (321)
Realized (loss) in Derivative instruments (In thousands)(2)	(109)	
NGL		
Quantity settled (Bbl)	427,700	63,000
Decrease in NGL sales revenue (In thousands)(1)	$	$ (1,186)
Realized (loss) in Derivative instruments (In thousands)(2)	(2,395)	
Natural Gas		
Quantity settled (MMBtu)	1,820,000	4,500,000
Increase in Natural gas sales revenue (In thousands)(1)(3)	$	$ 7,271
Realized gain in Derivative instruments (In thousands)(2)	4,495	

(1) For the three months ended March 31, 2011, amount represents the realized hedge gains/(losses) reclassified from Accumulated other comprehensive income into the respective commodity Revenue line item for derivatives designated as hedging instruments.

(2) For the three months ended March 31, 2012, amount represents the realized derivative gains/(losses) and the recognition of realized gains/(losses) reclassified from Accumulated other comprehensive income resulting from the Company s discontinuance of hedge accounting effective January 1, 2012.

(3) For the three months ended March 31, 2011, amount excludes approximately $2.9 million of realized gains associated with the termination of derivatives in 2011 used to hedge production from the Company s DJ Basin properties, which were divested in March 2011.

In accordance with the authoritative guidance for derivatives, all derivative instruments, not designated as a normal purchase sale, are recorded on the balance sheet at fair market value. For derivative instruments that were designated and qualified as cash flow hedges prior to January 1, 2012, the effective portion of the gain or loss on the derivative was reported as a component of other comprehensive income and reclassified into earnings in the same period during which the hedged transaction affected earnings.

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. As a result, our derivative contracts are marked-to-market each quarter with fair value gains and losses, both realized and unrealized, recognized currently within Revenues Derivative instruments on our Consolidated Statement of Operations. Consequently, we expect continued volatility in our reported earnings as changes occur in the commodity indices. Cash flow is only impacted to the extent the actual settlements under the contracts result in us making or receiving a payment from the counterparty.

As of March 31, 2012, our derivative positions are with counterparties who are also lenders under our credit facilities. This allows us to satisfy any need for margin obligations resulting from an adverse change in the fair market value of our derivative contracts with the collateral securing our credit facilities, thus eliminating the need for independent collateral postings. As of March 31, 2012, we had no deposits for collateral regarding our commodity derivative positions.

Governmental Regulation

Climate Change. Current and future regulatory initiatives directed at climate change may increase our operating costs and may, in the future, reduce the demand for some of our produced materials. Such initiatives may contain a cap and trade approach to greenhouse gas regulation, which would require companies to hold sufficient emission allowances to cover their greenhouse gas emissions. Over time, the total number of allowances would be reduced or expire, thereby relying on market-based incentives to allocate investment in emission reductions across the economy. As the number of available allowances declines, the cost would presumably increase. While the current prospect for such climate change legislation by the current U.S. Congress appears to be low, several states have adopted, or are in the process of adopting, greenhouse gas reporting or cap-and-trade programs. Therefore, while

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the outcome of the federal and state legislative processes is currently uncertain, if such an approach were adopted (either by domestic legislation, international treaty obligation or domestic regulation), we would expect our operating costs to increase as we buy additional allowances or embark on emission reduction programs.

Even without further federal legislation, the EPA has begun to regulate greenhouse gas emissions. In 2009 and 2010, the EPA promulgated new greenhouse gas reporting rules, requiring certain petroleum and natural gas facilities and facilities that emit more than 25,000 tons per year of carbon dioxide equivalents (CO_2e) to prepare and file annual emission reports. These rules, which are currently in effect and to which some of our facilities are subject, require some data reporting in 2012 for our facilities that emitted more than 25,000 tons of CO_2e in 2011. In addition, in 2010, the EPA issued a new tailoring rule, which imposes additional permitting requirements on certain stationary sources emitting over 75,000 tons per year of CO_2e. This rule does not currently affect our operations but may as our operations grow. Future federal or state regulatory initiatives on GHG regulation could increase our operating and compliance costs, although we are not situated differently in this respect from our competitors in the industry.

On April 17, 2012, the EPA approved final regulations under the federal Clean Air Act that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds (VOCs) and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule includes a 95 percent reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on hydraulically fractured wells constructed or refractured after January 1, 2015. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment, as well as the facilities of our transportation and processing providers. These rules will require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells by January 1, 2015. Compliance with such rules could result in significant costs, including increased capital expenditures, operating costs, and processing and transportation fees, and could adversely impact our business.

Hydraulic Fracturing. Various federal and state initiatives are underway to regulate, or further investigate, the environmental impacts of hydraulic fracturing, a practice that involves the pressurized injection of water, chemicals and other substances into rock formation to stimulate production of oil and natural gas. The U.S. Congress has considered legislation to amend the federal Safe Drinking Water Act (SDWA) to subject hydraulic fracturing operations to regulation under the SDWA s Underground Injection Control Program and to require the disclosure of chemicals used in the hydraulic fracturing process. Any such legislation could make it easier for third parties opposed to hydraulic fracturing to initiate legal proceedings against us. In addition, the federal government is currently undertaking several studies of hydraulic fracturing s potential impacts, the results of which are expected between now and 2014. The EPA is developing permitting guidance under the SDWA for hydraulic fracturing activities that use diesel fuels in fracturing fluids. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate waste water discharges from hydraulic fracturing and other natural gas production. While we are in material compliance with applicable environmental laws and regulations, the increased legislation, regulation or enforcement of hydraulic fracturing operations at the federal level could lead to operational delays, increased operating costs and additional regulatory burdens for our business.

Furthermore, a number of states, local governments and regulatory commissions have adopted, or are evaluating the adoption of, legislation or regulations that could impose more stringent permitting, disclosure, well construction and wastewater disposal requirements on hydraulic fracturing operations. Several states, including Texas and Montana where we do business, have recently adopted regulations requiring public disclosure of fracturing fluid constituents, among other requirements. Because we already participate in public disclosure on the FracFocus.com internet site we do not anticipate experiencing a material adverse effect from such regulations. The outcome for other proposed state, regional and local regulations is uncertain, but potential increased legislation, regulation or enforcement of hydraulic fracturing at the state, regional or local level could reduce our drilling activity or increase our operating costs.

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 within 360 days from the date of enactment. CFTC rulemaking is ongoing. 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. Of particular concern, the Dodd-Frank Act does not explicitly exempt end users (such as us) from the requirements to post margin in connection with hedging activities. 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.

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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.

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.

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 marked-to-market value of our cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the marked-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and will be reclassified into earnings in future periods as the underlying hedged transactions affect earnings. We expect to reclassify into earnings $2.7 million of unrealized gains during 2012 and $0.1 million of unrealized losses during 2013 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 marked-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 impact to cash flow occurs upon settlement of the underlying contract.

Recent Accounting Developments

For a discussion of recent accounting developments, see Note 2 to the Consolidated Financial Statements (Unaudited) in Part I. Item 1. Financial Statements of this Form 10-Q.

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 March 31, 2012, we had open crude oil derivative contracts in a net liability position with a fair value of $17.8 million. A ten percent increase in crude oil prices would reduce the fair value by approximately $23.8 million, while a ten percent decrease in crude oil prices would increase the fair value by approximately $16.1 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.

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As of March 31, 2012, we had open NGL derivative contracts in a net liability position with a fair value of $11.2 million. A ten percent increase in NGL prices would reduce the fair value by approximately $17.3 million, while a ten percent decrease in NGL prices would increase the fair value by approximately $17.5 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.

As of March 31, 2012, we had open natural gas derivative contracts in an asset position with a fair value of $14.7 million. A ten percent increase in natural gas prices would reduce the fair value by approximately $0.9 million, while a ten percent decrease in natural gas prices would increase the fair value by approximately $0.9 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.

Our derivative instruments are with counterparties who are lenders in our credit facilities. 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 March 31, 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 March 31, 2012. We evaluated non-performance risk using the current credit default swap values and default probabilities for the Company and counterparties and recorded a downward adjustment to the fair value of our derivative instruments in the amount of $0.2 million as of March 31, 2012.

We entered into oil, NGL and natural gas price derivative contracts with respect to a portion of our expected production through 2014. 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 March 31, 2012, 73% of our crude oil derivative transactions represented hedged prices of crude oil at the West Texas Intermediate on the NYMEX with the remaining 27% 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 the 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 then. We mark-to-market the fair values of our derivative instruments on a quarterly basis.

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 March 31, 2012. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of March 31, 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 March 31, 2012 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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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.

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.

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 March 31, 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
January 1 January 31	72,020	$ 44.40		
February 1 February 29	36,224	50.87		
March 1 March 31	12,657	52.11		
Total	120,901	$ 47.15		

(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
10.51	Fifth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 25, 2012, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (incorporated herein by reference to Exhibit 10.51 to the Company s Current Report on Form 8-K filed on April 30, 2012 (Registration No. 000-51801)).
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, Chief Financial Officer and Treasurer

(Duly Authorized Officer and Principal Financial Officer)

Date: May 8, 2012

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ROSETTA RESOURCES INC.

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