Rosetta Resources Inc.
Form 10-Q
November 06, 2013
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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 September 30, 2013

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.)**
1111 Bagby Street, Suite 1600	
Houston, TX	**77002**
(Address of principal executive offices)	**(Zip Code)**

(713) 335-4000

(Registrant s telephone number, including area code)

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, $0.001 par value per share, outstanding as of October 29, 2013 was 61,267,604 which excludes unvested restricted stock awards.

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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)

	September 30, 2013 (Unaudited)	December 31, 2012
Assets		
Current assets:		
Cash and cash equivalents	$ 63,956	$ 36,786
Accounts receivable, net	115,057	103,828
Derivative instruments	10,941	14,437
Prepaid expenses	7,525	5,742
Deferred income taxes	6,546	311
Other current assets	1,285	1,456
Total current assets	205,310	162,560
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	3,629,438	2,829,431
Unproved/unevaluated properties, not subject to amortization	803,493	95,540
Gathering systems and compressor stations	149,471	104,978
Other fixed assets	21,769	16,346
	4,604,171	3,046,295
Accumulated depreciation, depletion and amortization, including impairment	(1,955,838)	(1,808,190)
Total property and equipment, net	2,648,333	1,238,105
Other assets:		
Deferred loan fees	16,998	7,699
Derivative instruments	8,245	6,790
Other long-term assets	367	262
Total other assets	25,610	14,751
Total assets	$ 2,879,253	$ 1,415,416
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$ 3,718	$ 1,874

Accrued liabilities	188,093	120,336
Royalties and other payables	80,838	61,637
Derivative instruments	1,534	
Total current liabilities	274,183	183,847
Long-term liabilities:		
Derivative instruments		563
Long-term debt	1,175,000	410,000
Deferred income taxes	99,333	10,086
Other long-term liabilities	15,127	6,921
Total liabilities	1,563,643	611,417
Commitments and Contingencies (Note 9)		
Stockholders' equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2013 or 2012		
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 61,985,618 shares and 53,145,853 shares at September 30, 2013 and December 31, 2012, respectively	61	53
Additional paid-in capital	1,179,125	830,539
Treasury stock, at cost; 719,550 and 581,717 shares at September 30, 2013 and December 31, 2012, respectively	(24,317)	(17,479)
Accumulated other comprehensive income (loss)	(65)	(63)
Retained earnings (Accumulated deficit)	160,806	(9,051)
Total stockholders' equity	1,315,610	803,999
Total liabilities and stockholders' equity	$ 2,879,253	$ 1,415,416

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share and share amounts)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	**2012**	**2013**	**2012**
Revenues:				
Oil sales	$ 140,172	$ 92,377	$ 353,119	$ 221,574
NGL sales	50,857	35,179	144,236	114,867
Natural gas sales	34,136	23,019	108,369	62,815
Derivative instruments	(30,597)	(27,823)	3,484	35,935
Total revenues	194,568	122,752	609,208	435,191
Operating costs and expenses:				
Lease operating expense	18,963	10,697	44,826	29,434
Treating and transportation	18,807	12,807	52,414	37,330
Production taxes	4,787	5,402	15,442	11,551
Depreciation, depletion and amortization	60,915	40,432	153,382	107,328
General and administrative costs	18,790	19,972	52,830	48,454
Total operating costs and expenses	122,262	89,310	318,894	234,097
Operating income	72,306	33,442	290,314	201,094
Other expense (income):				
Interest expense, net of interest capitalized	6,907	6,346	26,009	18,316
Interest income		(2)		(6)
Other expense (income), net	620	(330)	1,061	(331)
Total other expense	7,527	6,014	27,070	17,979
Income before provision for income taxes	64,779	27,428	263,244	183,115
Income tax expense	23,754	9,739	93,387	66,160
Net income	$ 41,025	$ 17,689	$ 169,857	$ 116,955
Earnings per share:				
Basic	$ 0.67	$ 0.34	$ 2.95	$ 2.23
Diluted	$ 0.67	$ 0.33	$ 2.93	$ 2.21

Weighted average shares outstanding:

Basic	61,152	52,534	57,656	52,478
Diluted	61,364	52,883	57,924	52,863

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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net income	$ 41,025	$ 17,689	$ 169,857	$ 116,955
Other comprehensive income (loss):				
Amortization of accumulated other comprehensive gain (loss) related to de-designated hedges, net of income taxes of $58 and $351 for the three months ended September 30, 2013 and 2012, respectively, and $(97) and $784 for the nine months ended September 30, 2013 and 2012, respectively	(102)	(616)	171	(1,372)
Postretirement medical benefits prior service benefit (cost), net of income taxes of $(3) and $98 for the three and nine months ended September 30, 2013, respectively	6		(173)	
Other comprehensive income (loss)	(96)	(616)	(2)	(1,372)
Comprehensive income	$ 40,929	$ 17,073	$ 169,855	$ 115,583

See accompanying notes to the consolidated financial statements.

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Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Cash flows from operating activities:		
Net income	$ 169,857	$ 116,955
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	153,382	107,328
Deferred income taxes	89,358	66,160
Amortization of deferred loan fees recorded as interest expense	7,674	2,310
Stock-based compensation expense	8,293	12,036
Loss (gain) due to change in fair value of derivative instruments	3,280	(19,069)
Change in operating assets and liabilities:		
Accounts receivable	(11,230)	(10,069)
Prepaid expenses	(652)	(223)
Other current assets	171	278
Long-term assets	(105)	650
Accounts payable	1,844	(1,377)
Accrued liabilities	30,503	(18,665)
Royalties and other payables	19,201	5,062
Other long-term liabilities	4,189	(2,086)
Excess tax benefit from share-based awards	(6,342)	
Net cash provided by operating activities	469,423	259,290
Cash flows from investing activities:		
Acquisitions of oil and gas assets	(952,703)	
Additions to oil and gas assets	(568,140)	(458,523)
Disposals of oil and gas assets	(1,402)	88,489
Net cash used in investing activities	(1,522,245)	(370,034)
Cash flows from financing activities:		
Borrowings on Credit Facility	580,000	210,000
Payments on Credit Facility	(515,000)	(70,000)
Payments on Restated Term Loan		(20,000)
Issuance of Senior Notes	700,000	
Proceeds from issuance of common stock	329,008	
Deferred loan fees	(18,102)	(1,979)

Proceeds from stock options exercised		4,582		898
Purchases of treasury stock		(6,838)		(6,048)
Excess tax benefit from share-based awards		6,342		
Net cash provided by financing activities		1,079,992		112,871
Net increase in cash		27,170		2,127
Cash and cash equivalents, beginning of period		36,786		47,050
Cash and cash equivalents, end of period	$	63,956	$	49,177
Supplemental disclosures:				
Capital expenditures included in accrued liabilities	$	126,780	$	92,222

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 Shares	Common Stock Amount	Additional Paid-In Capital	Treasury Stock Shares	Treasury Stock Amount	Accumulated Other Comprehensive Income/(Loss)	Retained Earnings / (Accumulated Deficit)	Total Stockholders Equity
Balance at December 31, 2012	53,145,853	$ 53	$ 830,539	581,717	$ (17,479)	$ (63)	$ (9,051)	$ 803,999
Issuance of common stock	8,050,000	8	329,000					329,008
Excess tax benefit from share - based awards			6,342					6,342
Stock options exercised	352,481		4,582					4,582
Treasury stock - employee tax payment				137,833	(6,838)			(6,838)
Stock - based compensation			8,662					8,662
Vesting of restricted stock	437,284							
Comprehensive income						(2)	169,857	169,855
Balance at September 30, 2013	61,985,618	$ 61	$ 1,179,125	719,550	$ (24,317)	$ (65)	$ 160,806	$ 1,315,610

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 located in the Eagle Ford shale in South Texas and in the Permian Basin in West Texas.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments, consisting of normal recurring adjustments necessary to fairly state the financial statements, have been included. Results of operations for interim periods are not necessarily indicative of the results of operations that may be expected for the entire year. In addition, these financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the U.S. (GAAP). These financial statements and notes should be read in conjunction with the Company s audited Consolidated Financial Statements and the notes thereto included in the Company s Annual Report on Form 10-K for the year ended December 31, 2012 (2012 Annual Report).

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2012 Annual Report. There have been no changes to the Company s significant accounting policies since December 31, 2012.

Recent Accounting Developments

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

Comprehensive Income. In June 2011, the Financial Accounting Standards Board (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. In February 2013, the FASB further clarified this guidance relating to the presentation of reclassification adjustments stating that an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income. The Company adopted the provisions of the initial guidance effective January 1, 2012 and the provisions of the February 2013 amendment effective January 1, 2013. See the Consolidated Statement of Comprehensive Income, Note 4 Commodity Derivative Contracts and Note 11 Stock-Based Compensation and Employee Benefits.

Offsetting Assets and Liabilities. In December 2011, the FASB issued authoritative guidance requiring entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The objective of the disclosure is to facilitate comparison between those entities that prepare their financial statements under GAAP and those entities that prepare their financial statements under International Financial Reporting

Standards (IFRS). In January 2013, the FASB issued additional guidance clarifying the scope of these disclosures to include bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing and lending transactions that are either offset or subject to an enforceable master netting arrangement or similar agreement. The Company has adopted this guidance effective January 1, 2013. 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.

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(3) Property and Equipment

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

	September 30, 2013	December 31, 2012
	(In thousands)	
Proved properties	$ 3,629,438	$ 2,829,431
Unproved/unevaluated properties	803,493	95,540
Gathering systems and compressor stations	149,471	104,978
Other fixed assets	21,769	16,346
Total property and equipment, gross	4,604,171	3,046,295
Less: Accumulated depreciation, depletion, and amortization, including impairment	(1,955,838)	(1,808,190)
Total property and equipment, net	$ 2,648,333	$ 1,238,105

Acquisitions

Permian Basin Acquisition. On March 14, 2013, the Company entered into a purchase and sale agreement with Comstock Oil & Gas, LP (Comstock) to purchase producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas for $768 million, subject to customary closing adjustments, including adjustments based upon title and environmental due diligence (the Permian Acquisition). The Company completed the Permian Acquisition on May 14, 2013 (the Permian Acquisition Date), with an effective date of January 1, 2013, for total cash consideration of $825.2 million, subject to further customary closing adjustments. The Permian Acquisition was financed with the proceeds from the Company s issuance of the 5.625% Senior Notes, as described in Note 7 Long-Term Debt, and the common stock offering described in Note 10 Equity. In connection with the Permian Acquisition and related financings, the Company incurred total transaction costs of approximately $31.0 million, including (i) $5.6 million of commitment fees and related expenses associated with a bridge credit facility (Bridge Credit Facility), which were recorded as Interest expense since the Company did not borrow under the Bridge Credit Facility, (ii) $10.0 million of debt issuance costs paid in connection with the issuance of the 5.625% Senior Notes, which were deferred and are being amortized over the term of these senior notes, (iii) $13.1 million of equity issuance costs and related expenses associated with the common stock offering, which were reflected as a reduction of equity proceeds, and (iv) $2.3 million of consulting, investment, advisory, legal and other acquisition-related fees, which were expensed and are included in General and administrative costs.

Gates Ranch Acquisition. In the second quarter of 2013, the Company acquired the remaining 10% working interest in certain producing wells in certain leases of its Gates Ranch leasehold located in the Eagle Ford shale (the Gates Acquisition) for total cash consideration of approximately $128.1 million. The transaction closed on June 5, 2013 (the Gates Acquisition Date) and was financed with borrowings under the Company s Credit Facility, as described in Note 7 Long-Term Debt. As of the Gates Acquisition Date, the Company now owns 100% working interest in the entire Gates Ranch leasehold.

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Both of the above transactions were accounted for under the acquisition method of accounting, whereby the purchase price was allocated to the assets acquired and liabilities assumed based on their estimated fair values, with any excess of the purchase price over the estimated fair value of the identifiable net assets acquired recorded as goodwill (or shortfall of purchase price versus net fair value recorded as bargain purchase). Based on the preliminary purchase price allocation for these acquisitions, no goodwill or bargain purchase was recognized. The combined cash consideration paid for these transactions and the assets and liabilities recognized at the acquisition dates are shown in the table below. Such purchase price allocations are preliminary and may be subject to change based upon customary closing adjustments:

	Total Allocation (in thousands)
Cash consideration	$ 953,302
Fair value of assets acquired:	
Other fixed assets	$ 600
Oil and natural gas properties	
Proved properties	290,333
Unproved/unevaluated properties	663,300
Total assets acquired	$ 954,233
Fair value of liabilities assumed:	
Asset retirement obligations	$ 931
Net assets acquired	$ 953,302

The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties included estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; (v) future cash flows; and (vi) a market-based weighted average cost of capital rate. These inputs required significant judgments and estimates by the Company s management at the time of the valuation and are the most sensitive and subject to change.

The results of operations attributable to the Permian Basin assets and the acquired Gates Ranch working interests were included in the Company s Consolidated Statement of Operations beginning on May 14, 2013 (Permian Acquisition) and June 5, 2013 (Gates Acquisition), respectively. Revenues of $24.5 million and $37.8 million and net income of $16.8 million and $26.7 million from these acquired assets were generated in the three and nine months ended September 30, 2013, respectively, and are included in the Consolidated Statement of Operations for the three and nine months ended September 30, 2013.

The following unaudited pro forma information shows the pro forma effects of the acquisitions, the issuance of the 5.625% Senior Notes, the issuance of common stock in the equity offering and the use of proceeds from the debt and equity offerings. The unaudited pro forma information assumes the transactions and related financings occurred on January 1, 2012. The pro forma results of operations have been prepared by adjusting the Company s historical results to include the historical results of the acquired assets based on information provided by the seller, the Company s knowledge of the acquired properties and the impact of the Company s preliminary purchase price allocation. The Company believes the assumptions used provide a reasonable basis for representing the pro forma significant effects directly attributable to the acquisitions and associated financings. The pro forma results of operations do not include any cost savings or other synergies that may result from the Permian Acquisition or any estimated costs that have been or will be incurred by the Company to integrate the Permian assets. The pro forma information does not purport to represent what the Company s results of operations would have been if such transactions had occurred on January 1, 2012:

	Three Months Ended September 30, 2013 (1)	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(In thousands, except per share and share data)		(In thousands, except per share and share data)	
Total revenues	$ 194,568	$ 140,117	$ 641,750	$ 477,746
Net income	41,025	17,033	162,755	111,657
Earnings per share:				
Basic	$ 0.67	$ 0.28	$ 2.67	$ 1.84
Diluted	$ 0.67	$ 0.28	$ 2.66	$ 1.83
Weighted average shares outstanding:				
Basic	61,152	60,584	61,011	60,528
Diluted	61,364	60,933	61,279	60,913

(1) No pro forma adjustments were made for the period as the acquisitions and related financings are included in the Company s historical results.

Additional Disclosures about Property and Equipment

The Company capitalizes internal costs directly identified with acquisition, exploration and development activities. The Company capitalized $1.6 million and $1.2 million of internal costs for the three months ended September 30, 2013 and 2012, respectively, and $5.5 million and $4.7 million for the nine months ended September 30, 2013 and 2012, respectively.

Oil and gas properties include unevaluated property costs of $803.5 million and $95.5 million as of September 30, 2013 and December 31, 2012, respectively, which are not being amortized. These amounts primarily represent acquisition costs of unproved properties and unevaluated exploration projects in which the Company owns a direct interest, including unevaluated leasehold associated with the Permian Acquisition. Such costs are periodically evaluated for impairment, and upon evaluation or impairment are transferred to the Company s full cost pool and amortized.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within its U.S. cost center. The Company s ceiling test was calculated using trailing twelve-month, unweighted-average first-day-of-the-month prices for oil and natural gas as of September 30, 2013, which were based on a West Texas Intermediate oil price of $91.69 per Bbl and a Henry Hub natural gas price of $3.60 per MMBtu (adjusted for basis and quality differentials), respectively. Utilizing these prices, the calculated ceiling amount exceeded the net capitalized cost of oil and natural gas properties. As a result, no write-down was recorded as of September 30, 2013. 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

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

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As of September 30, 2013, the following derivative contracts were outstanding with associated notional volumes and average underlying prices that represent hedged prices of commodities at various market locations:

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbl)	Total Notional Volume (Bbl)	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2013	Costless Collar	7,750	713,000	$ 80.16	$ 115.71
Crude oil	2014	Costless Collar	3,000	1,095,000	83.33	109.63
Crude oil	2013	Swap	3,000	276,000	95.72	
Crude oil	2014	Swap	6,000	2,190,000	93.13	
Crude oil	2015	Swap	7,000	2,555,000	88.17	
				6,829,000		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbl)	Total Notional Volume (Bbl)	Average Fixed Prices per Bbl
Crude oil	2013	Basis Swap	1,875	172,500	$ 5.80
Crude oil	2013	NYMEX Roll Swap	1,875	172,500	(0.18)
				345,000	

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbl)	Total Notional Volume (Bbl)	Average Fixed Prices per Bbl
NGL-Ethane	2013	Swap	3,000	276,000	$ 14.43
NGL-Propane	2013	Swap	2,270	208,840	46.34
NGL-Isobutane	2013	Swap	705	64,860	69.30
NGL-Normal Butane	2013	Swap	730	67,160	66.86
NGL-Pentanes Plus	2013	Swap	795	73,140	86.27
NGL-Ethane	2014	Swap	2,000	730,000	15.28
NGL-Propane	2014	Swap	1,535	560,275	43.75
NGL-Isobutane	2014	Swap	480	175,200	66.71
NGL-Normal Butane	2014	Swap	475	173,375	64.54
NGL-Pentanes Plus	2014	Swap	510	186,150	83.96
				2,515,000	

Product

	Settlement Period	Derivative Instrument	Notional Daily Volume (MMBtu)	Total Notional Volume (MMBtu)	Average Floor/Fixed Prices per MMBtu	Average Ceiling Prices per MMBtu
Natural gas	2013	Costless Collar	30,000	2,760,000	$ 3.50	$ 4.93
Natural gas	2014	Costless Collar	50,000	18,250,000	3.60	4.94
Natural gas	2015	Costless Collar	50,000	18,250,000	3.60	5.04
Natural gas	2013	Swap	30,000	2,760,000	4.11	
Natural gas	2014	Swap	30,000	10,950,000	4.07	
Natural gas	2015	Swap	40,000	14,600,000	4.18	
				67,570,000		

As of September 30, 2013, the Company s derivative instruments were with counterparties who are lenders under the Company s senior secured revolving credit facility (the Credit Facility). This practice allows the Company to satisfy any need for any margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its Credit Facility, thus eliminating the need for independent collateral postings. The Company s ability to continue satisfying any applicable margin requirements in this manner may be subject to change as described in Items 1 and 2. Business and Properties Government Regulation in the Company s 2012 Annual Report. As of September 30, 2013, the Company had no deposits for collateral relating to its commodity derivative instruments.

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Discontinuance of Hedge Accounting

Effective January 1, 2012, the Company elected to de-designate all commodity contracts previously designated as cash flow hedges as of December 31, 2011, and elected to discontinue hedge accounting prospectively. Accumulated other comprehensive income included $2.6 million ($1.6 million after tax) of unrealized net gains, representing the mark-to-market value of the Company s cash flow hedges as of December 31, 2011. As a result of discontinuing hedge accounting, the mark-to-market values included in Accumulated other comprehensive income as of the de-designation date were frozen and are being reclassified into earnings as the underlying hedged transactions affect earnings. During the three and nine months ended September 30, 2013, the Company reclassified a $0.2 million ($0.1 million after tax) unrealized net gain and a $0.3 million ($0.2 million after tax) unrealized net loss, respectively, into earnings from Accumulated other comprehensive income. The Company expects to reclassify an additional $0.2 million ($0.1 million after tax) of unrealized net gains into earnings from Accumulated other comprehensive income during the last three months of 2013.

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

Additional Disclosures about Derivative Instruments

Authoritative guidance for derivatives requires companies to recognize all derivative instruments as either assets or liabilities at fair value in the Company s financial statements. The following table sets forth information on the location and amounts of the Company s derivative instrument fair values in the Consolidated Balance Sheet as of September 30, 2013 and December 31, 2012, respectively:

		Asset (Liability) Fair Value	
		September 30, 2013	**December 31, 2012**
Commodity derivative contracts	**Location on Consolidated Balance Sheet**	(In thousands)	
Oil	Derivative instruments - current assets	$ (872)	$ 564
Oil	Derivative instruments - non-current assets	238	3,329
Oil	Derivative instruments - current liabilities	(5,424)	
NGL	Derivative instruments - current assets	6,675	8,361
NGL	Derivative instruments - non-current assets	2,128	3,534
NGL	Derivative instruments - current liabilities	1,863	
NGL	Derivative instruments - non-current liabilities		(563)
Natural gas	Derivative instruments - current assets	5,138	5,512
Natural gas	Derivative instruments - non-current assets	5,879	(73)
Natural gas	Derivative instruments - current liabilities	2,027	
Total derivative fair value not designated as hedging instruments		**$ 17,652**	**$ 20,664**

The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the three and nine months ended September 30, 2013 and 2012, respectively:

Location on Consolidated Statement of Operations	Description of Gain (Loss)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
		(In thousands)			
Derivative instruments	Gain recognized in income	1,473	7,624	6,764	16,866
	Realized gain recognized in income	$ 1,473	$ 7,624	$ 6,764	$ 16,866
Derivative instruments	(Loss) gain recognized in income due to changes in fair value	$ (32,229)	$ (36,414)	$ (3,012)	$ 16,913
Derivative instruments	Gain (loss) reclassified from Accumulated OCI	159	967	(268)	2,156
	Unrealized (loss) gain recognized in income	$ (32,070)	$ (35,447)	$ (3,280)	$ 19,069
	Total commodity derivative (loss) gain recognized in income	$ (30,597)	$ (27,823)	$ 3,484	$ 35,935

(5) Fair Value Measurements

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

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

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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 along with their placement within the fair value hierarchy levels. The Company determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes any transfers at the end of the reporting period.

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

	Fair value as of September 30, 2013				
	Level 1	Level 2	Level 3	Netting (1)	Total
			(In thousands)		
Assets:					
Money market funds	$	$ 1,035	$	$	$ 1,035
Commodity derivative contracts			25,162	(5,976)	19,186
Liabilities:					
Commodity derivative contracts			(7,510)	5,976	(1,534)
Total fair value	$	$ 1,035	$ 17,652	$	$ 18,687

	Fair value as of December 31, 2012				
	Level 1	Level 2	Level 3	Netting (1)	Total
			(In thousands)		
Assets:					
Money market funds	$	$ 1,035	$	$	$ 1,035
Commodity derivative contracts			27,554	(6,327)	21,227
Liabilities:					

Commodity derivative contracts			(6,890)	6,327	(563)
Total fair value	$	$ 1,035	$ 20,664	$	$ 21,699

(1) Represents the impact of netting commodity derivative assets and liabilities with counterparties where the Company has the contractual right and intends to net settle. No margin or collateral balances are deposited with counterparties and as such, gross amounts are offset to determine the net amounts presented in the Consolidated Balance Sheet.

The Company s Level 3 instruments include commodity derivative contracts for which fair value is determined by a third-party provider. Although the Company compares the fair values derived from the third-party provider with its counterparties, the Company does not currently have sufficient corroborating market evidence to support classifying these contracts as Level 2 instruments and does not have access to the specific valuation models or certain inputs used by its third-party provider or counterparties. Therefore, these commodity derivative contracts are classified as Level 3 instruments.

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The following table presents a range of the unobservable inputs provided by our third-party provider utilized in the fair value measurements of the Company s assets and liabilities classified as Level 3 instruments as of September 30, 2013 (in thousands):

Level 3 Instrument	**Asset (Liability)**	**Valuation Technique**	**Unobservable Input**	**Range Minimum**	**Range Maximum**	**Weighted Average**
Oil NYMEX roll swap	$ (201)	Discounted cash flow	Forward price curve-NYMEX roll swap	$ 0.48	$ 2.05	$ 0.99
Oil basis swap	515	Discounted cash flow	Forward price curve-basis swap	2.20	3.39	2.81
Oil swaps	(7,247)	Discounted cash flow	Forward price curve-swaps	86.51	102.20	92.19
Oil costless collars	876	Option model	Forward price curve-costless collar option values	(2.42)	4.65	0.48
NGL swaps	10,727	Discounted cash flow	Forward price curve-swaps	0.25	2.07	0.84
NGL swaps	(62)	Discounted cash flow	Forward price curve-swaps	2.07	2.07	2.07
Natural gas swaps	7,373	Discounted cash flow	Forward price curve-swaps	3.42	4.26	3.87
Natural gas costless collars	5,671	Option model	Forward price curve-costless collar option values	(0.26)	0.37	0.14
Total derivative fair value	$ 17,652					

The determination of derivative fair values by the third-party provider incorporates a credit adjustment for nonperformance risk, including the credit standing of the counterparties involved, and the impact of the Company s nonperformance risk on its liabilities. The Company recorded a downward adjustment to the fair value of its derivative instruments in the amount of $0.1 million as of September 30, 2013.

The significant unobservable inputs for Level 3 derivative contracts include forward price curves and option values. Significant increases (decreases) in the quoted forward prices for commodities and option values 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.

	Derivative Asset (Liability)	**Money Market Funds Asset**	**Total**

		(Liability)	
		(In thousands)	
Balance at January 1, 2013	$ 20,664	$	$ 20,664
Total Gains or (Losses) (Realized or Unrealized):			
Included in Earnings	3,752		3,752
Purchases, Issuances and Settlements:			
Settlements	(6,764)		(6,764)
Transfers in and out of Level 3			
Balance at September 30, 2013	$ 17,652	$	$ 17,652

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

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

Fair Value of Other Financial Instruments

All of the Company s other financial instruments (excluding derivatives) are presented on the balance sheet at carrying value. As of September 30, 2013, the carrying values 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 all such financial instruments are considered Level 1 instruments.

The Company s debt consists of $200 million in aggregate principal amount of 9.500% Senior Notes due 2018 (the 9.500% Senior Notes), $700 million in aggregate principal amount of 5.625% Senior Notes due 2021 (the 5.625% Senior Notes) and borrowings under the Credit Facility. The fair values of the Company s 9.500% Senior Notes and 5.625% Senior Notes are based upon unadjusted quoted market prices and are considered Level 1 instruments. The Company s borrowings under the Credit Facility approximate fair value as the interest rates are variable and reflective of current market rates, and are therefore considered a Level 1 instrument. As of September 30, 2013, the carrying amount of total debt was $1.175 billion and the estimated fair value of total debt was $1.155 billion.

(6) Asset Retirement Obligations

The following table provides a rollforward of the Company s asset retirement obligations (ARO). Liabilities incurred during the period include additions to obligations and obligations incurred from acquisitions. Liabilities settled during the period include settlement payments for obligations. Activity related to the Company s ARO is as follows:

	Nine Months Ended September 30, 2013 (In thousands)
ARO as of December 31, 2012	$ 8,400
Liabilities incurred during period	1,033
Liabilities settled during period	(1,354)
Accretion expense	430
ARO as of September 30, 2013	$ 8,509

As of September 30, 2013, the $1.8 million current portion of the total ARO is included in Accrued liabilities, and the $6.7 million long-term portion of ARO is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Long-Term Debt

Senior Secured Revolving Credit Facility. On April 12, 2013, the Company entered into the Sixth Amendment to the Amended and Restated Senior Revolving Credit Agreement (the Amendment) with Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto. The Amendment, among other things, (i) increased the borrowing base to $800.0 million; (ii) increased the maximum credit amount under the Credit Facility to $1.5 billion; (iii) extended the maturity date to April 12, 2018; and (iv) provided for restrictions on the Company s ability to pay dividends to its equity holders to be eased upon the Company acquiring investment grade unsecured debt ratings from Moody s and Standard & Poor s.

On July 30, 2013, the Company entered into the Seventh Amendment to the Amended and Restated Senior Revolving Credit Agreement (the Amendment) with Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto. The Amendment primarily revises and clarifies language in connection with the hedging restrictions in the Credit Agreement, insofar as it relates to the Company s ability to maintain incremental hedges added during a pre-acquisition period after such acquisition is successfully consummated.

At September 30, 2013, the Company s borrowing base and commitments under the Credit Facility were $800.0 million. Availability under the Credit Facility is restricted to a borrowing base and committed amount, which are 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 and committed amount 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 lower the borrowing base and committed amount.

As of September 30, 2013, the Company had $275.0 million outstanding with $525.0 million of available borrowing capacity under its Credit Facility. Amounts outstanding under the Credit Facility bear interest at specified margins over the London Interbank Offered Rate (LIBOR) of 1.50% to 2.50%. Additionally, the Company can borrow under the Credit Facility at the Alternative Base Rate (ABR) which is typically based upon the Prime Rate in effect on such day plus a margin of 0.5% to 1.5% depending on the Company s utilization percentage. The weighted average borrowing rate for the nine months ended September 30, 2013 under the Credit Facility was 3.28%, inclusive of interest and commitment fees. Borrowings under the Credit Facility are collateralized by 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 proved 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 also subject to certain financial covenants including the requirement to maintain a minimum current ratio of consolidated current assets, including the unused amount of available borrowing capacity, to consolidated current liabilities, excluding certain non-cash obligations, of not less than 1.0 to 1.0 as of the end of each fiscal quarter. The terms of the credit agreement also require the maintenance of a maximum leverage ratio of total debt to earnings before interest expense, income taxes and noncash items, such as depreciation, depletion, amortization and impairment, of not greater than 4.0 to 1.0, calculated at the end of each fiscal quarter for the four fiscal quarters then ended, measured quarterly after giving pro forma effect to acquisitions and divestitures. As of September 30, 2013, the Company s current ratio was 2.7 and leverage ratio was 2.0. 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.

9.500% 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 in a private offering. Interest is payable on the 9.500% Senior Notes semi-annually on April 15 and October 15. The 9.500% Senior Notes were issued under an indenture (the 9.500% Senior Notes Indenture) with Wells Fargo Bank, National Association, as trustee. Under the indenture, the Company has the option to redeem the notes on or after April 15, 2014 at a price of $104.75. Provisions of the 9.500% Senior Notes 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 9.500% Senior Notes Indenture also contains customary events of default. On September 21, 2010, the Company exchanged all of the privately placed 9.500% Senior Notes for registered 9.500% Senior Notes which contain terms substantially identical to the terms of the privately placed notes.

5.625% Senior Notes. On May 2, 2013, the Company completed its public offering of $700.0 million in aggregate principal amount of 5.625% Senior Notes due 2021. Interest is payable on the 5.625% Senior Notes semi-annually on May 1 and November 1. The 5.625% Senior Notes were issued under an indenture, as supplemented by a first supplemental indenture (the 5.625% Senior Notes Indenture) with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 9.500% Senior Notes Indenture. Net proceeds from the debt offering were used to fund a portion of the consideration for the Permian Acquisition.

Total Indebtedness. As of September 30, 2013, the Company had total outstanding borrowings of $1.175 billion. For the nine months ended September 30, 2013, the Company s weighted average borrowing rate was 5.95%, inclusive of interest and commitment fees.

(8) Income Taxes

The Company s effective tax rate for the three and nine months ended September 30, 2013 was 36.7% and 35.5%, respectively, compared to 35.5% and 36.1%, respectively, for the prior comparable periods in the prior year. The provision for income taxes for the three and nine months ended September 30, 2013 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. In addition, during the first quarter of 2013 there was a one-time favorable discrete adjustment of (2.9%) to reflect a change in the amount of deductible executive compensation. Excluding discrete items, the effective tax rate for the nine months ended September 30, 2013 was 36.3%. As of September 30, 2013 and December 31, 2012, the Company had no unrecognized tax benefits. The Company does not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statutes of limitation within the next twelve months.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2013, the Company had a net deferred tax liability of $92.8 million resulting primarily from the differences between the book basis and tax basis of the Company s oil and natural gas properties, partially offset by net operating loss carryforwards.

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(9) Commitments and Contingencies

Firm Oil and Natural Gas Transportation and Processing Commitments. The Company has commitments for the transportation and processing of its production in the Eagle Ford area and has an aggregate minimum commitment to deliver 6.5 MMBbls of oil by the end of 2017 and 378 million MMBtus of natural gas by the end of 2023. The Company is required to make periodic deficiency payments for any shortfalls in delivering the minimum volumes under these commitments. Currently, the Company has insufficient production to meet all of these contractual commitments, and as of September 30, 2013, the Company has accrued deficiency fees of $6.5 million. Future obligations under firm oil and natural gas transportation and processing agreements as of September 30, 2013 are as follows:

		September 30, 2013 (In thousands)
2013	$	8,692
2014		34,486
2015		34,313
2016		33,844
2017		33,388
Thereafter through 2023		133,928
Total future obligations	$	278,651

Drilling Rig and Completion Services Commitments. Drilling rig and completion services commitments represent obligations with certain contractors to execute the Company s Eagle Ford and Permian Basin drilling programs, and payments under these commitments are accounted for as capital additions to oil and gas properties. As of September 30, 2013, the Company had one outstanding drilling rig commitment with a term greater than one year, and minimum contractual commitments due in the next twelve months are $4.6 million. As of September 30, 2013, the Company s minimum contractual commitments for completion services agreements for the stimulation, cementing and delivery of drilling fluids was $9.5 million.

Contingencies. The Company is party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. The Company has evaluated the need for a reserve for each respective matter in accordance with applicable accounting guidance and recorded a $0.5 million reserve related to a commercial dispute, which is included in Other expense (income), net in the Consolidated Statement of Operations for the three and nine months ended September 30, 2013 and Accrued liabilities in the Consolidated Balance Sheet as of September 30, 2013. The outcomes of all remaining matters are not known and the related damages, if any, cannot be reasonably estimated at this time. The Company intends to vigorously defend its position in all such disputes; however, it is remotely possible that an adverse decision or settlement of one or more of such matters could have a material effect on the Company, its financial condition, results of operations and cash flows.

(10) Equity

Earnings per Share. Basic earnings per share (EPS) is calculated by dividing net income (the numerator) by the weighted-average number of shares of common stock (excluding unvested restricted stock awards) outstanding during the period (the denominator). Diluted earnings per share incorporates the dilutive impact of outstanding stock options and unvested restricted stock awards using the treasury stock method.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Basic weighted average number of shares outstanding	61,152	52,534	57,656	52,478
Dilution effect of stock option and restricted shares at the end of the period	212	349	268	385
Diluted weighted average number of shares outstanding	61,364	52,883	57,924	52,863
Anti-dilutive stock awards and shares		1		2

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Common Stock Offering. On April 23, 2013, the Company completed its public offering of 7,000,000 shares of common stock at a price to the public of $42.50 per share ($40.80 per share, net of underwriting discount and structuring fee) for net proceeds of approximately $286.3 million including reimbursement by the underwriters. The Company also received net proceeds of approximately $43.0 million in connection with the underwriters full exercise of their over-allotment option to issue an additional 1,050,000 shares of common stock, which closed on April 29, 2013. The Company used net proceeds from the offering to repay outstanding indebtedness under its Credit Facility and to fund a portion of the consideration for the Permian Acquisition.

(11) Stock-Based Compensation and Employee Benefits

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 management. As of the indicated dates, stock-based compensation expense consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Total stock-based compensation	$ 3,621	$ 6,453	$ 8,662	$ 12,258
Capitalized in oil and gas properties	(221)	101	(369)	(222)
Net stock-based compensation expense	$ 3,400	$ 6,554	$ 8,293	$ 12,036

All stock-based compensation expense associated with restricted stock granted to employees and directors is recognized on a straight-line basis over the applicable remaining vesting period. For the three and nine months ended September 30, 2013, the Company recorded compensation expense of approximately $1.7 million and $4.6 million, respectively, related to these equity awards. As of September 30, 2013, unrecognized stock-based compensation expense related to unvested restricted stock was approximately $10.8 million.

Stock-based compensation expense associated with the PSUs granted to management is recognized over a three-year performance period. For the three and nine months ended September 30, 2013, the Company recognized compensation expense of $1.9 million and $4.0 million, respectively, associated with the PSUs. At the current fair value as of September 30, 2013 and assuming the Board elects the maximum available payout of 200% for all PSU metrics, unrecognized stock-based compensation expense related to the PSUs was approximately $13.4 million. The Company s total stock-based compensation expense will be measured and adjusted quarterly until settlement occurs, based on the Company s performance, expected payout and quarter-end closing common stock prices. For a more detailed description of the Company s PSU plans, including related performance conditions and structure, see the definitive proxy statement filed with respect to the Company s 2013 annual meeting under the heading Compensation Discussion and Analysis and the Company s 2012 Annual Report.

Postretirement Health Care. Effective January 1, 2013, the Company enacted a postretirement medical benefit plan covering eligible employees and their eligible dependents. Upon enactment, the Company recognized a $0.3 million liability related to the prior service of employees which is included as a component of Other comprehensive income, net of the related tax benefit. The Company recognizes periodic postretirement benefits cost as a component of General and administrative costs. For both the three and nine months ended September 30, 2013, this expense was immaterial.

(12) Guarantor Subsidiaries

The Company s 9.500% Senior Notes and 5.625% 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. 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.

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report includes forward-looking statements regarding the Company within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements other than statements of historical fact included in this report are forward-looking statements, including without limitation all statements regarding future plans, business objectives, strategies, expected future financial position or performance, expected future operational position or performance, budgets and projected costs, future competitive position, or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as may, will, could, should, would, expect, pl project, intend, anticipate, believe, estimate, forecast, predict, potential, pursue, target or continu 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 it 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, 2012 (the 2012 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:

- our ability to maintain leasehold positions that require exploration and development activities and material capital expenditures;
- unexpected difficulties in integrating our operations as a result of any significant acquisitions, including our recent acquisition of assets in the Permian Basin;
- 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 and/or lease operating expenditures;
- failure of joint interest partners to pay us our share of revenue;

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, equipment, goods, services and personnel;

changes or advances in technology;

potential reserve revisions;

the availability and cost, as well as limitations and constraints on infrastructure required, to gather, transport, process and market oil, NGLs and natural gas;

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

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

drilling, production 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 the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;

present and possible future claims, litigation and enforcement actions;

lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding 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 and 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 and development of oil or natural gas resources, including but not limited to the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of oil and natural gas.

Overview

The following discussion addresses material changes in our results of operations for the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 and material changes in our financial condition since December 31, 2012. This discussion includes operating results associated with our Permian Acquisition and Gates Acquisition, both acquired in the second quarter of 2013, and should be read in conjunction with our 2012 Annual Report, which includes disclosures regarding our critical accounting policies as part of Management s Discussion and Analysis of Financial Condition and Results of Operations.

Results for the three months ended September 30, 2013 included the following:

production of 4.7 MMBoe compared to 3.4 MMBoe for the three months ended September 30, 2012;

43 gross (42.5 net) operated wells drilled compared to 25 gross (24 net) wells drilled for the three months ended September 30, 2012; and

net income of $41.0 million, or $0.67 per diluted share, compared to $17.7 million, or $0.33 per diluted share, for the three months ended September 30, 2012.

Results for the nine months ended September 30, 2013 included the following:

production of 13.4 MMBoe compared to 9.5 MMBoe for the nine months ended September 30, 2012;

97 gross (96.5 net) operated wells drilled compared to 63 gross (61 net) wells drilled for the nine months ended September 30, 2012; and

net income of $169.9 million, or $2.93 per diluted share, compared to $117.0 million, or $2.21 per diluted share, for the nine months ended September 30, 2012.

Our principal operating and business strategy is focused on the acquisition, development and production of oil, NGLs and natural gas from unconventional resource plays. Our operations are primarily located in the Eagle Ford area in South Texas and in the Delaware Basin in West Texas, two of the most active unconventional resource plays in the U.S. During the first quarter of 2013, we entered into a purchase and sale agreement with Comstock Oil & Gas, LP to acquire producing and undeveloped assets covering 87,373 gross (53,306 net) acres in the oil-rich areas of the Permian Basin. The Permian Acquisition closed on May 14, 2013, with an effective date of January 1, 2013, for total consideration of $825.2 million, which includes the $768 million purchase price and $57.2 million in customary closing adjustments. The Permian Acquisition added roughly 40,000 net acres in the Wolfbone play in Reeves County in the Delaware Basin and 13,000 net acres in Gaines County in the Midland Basin. We estimate 1,300 gross, or nearly 800 net, vertical drilling locations can be developed based upon 40-acre spacing, with the potential for doubling such potential drilling locations based upon 20-acre spacing. Additionally, both Rosetta and the industry are actively participating in horizontal well applications to further enhance the value of this large resource. Our third quarter operational and financial results include a full quarter of operating results from the acquired Permian Basin assets.

During the second quarter of 2013, we also acquired for total consideration of $128.1 million the remaining 10% working interest in 46 gross producing wells and the leasehold associated with 170 future gross drilling locations in the Gates Ranch area of the Eagle Ford Shale. The net production associated with this acquisition was approximately 1,800 Boe/d at closing on June 5, 2013. We now own a 100% working interest in the entire Gates Ranch leasehold.

In the last three years, we have become a significant producer in the liquids-rich window of the Eagle Ford region and have established an inventory of lower-risk, higher-return drilling opportunities that offer more predictable and long-term production, reserve growth and a more valuable commodity mix. With our entry into the Permian Basin, we have increased our portfolio of long-lived, oil-rich resource projects that will further drive our long-term growth and sustainability. We will continue to consider investments in the Eagle Ford shale region, Permian Basin and other unconventional resource basins that offer a viable inventory of projects, including resource-based exploration projects and producing property acquisitions in early development stages.

Our current operations in the Eagle Ford shale are primarily focused in five areas. Our original discovery in 2009 is located in the 26,230-acre Gates Ranch leasehold in Webb County. We are also active in the Karnes Trough area, the Briscoe Ranch leasehold and Central Dimmit County, where our positions were delineated in 2010, 2011 and 2012, respectively. Earlier this year, we delineated the Tom Hanks lease in northern LaSalle County with an Eagle Ford discovery well completed in June 2013. Overall, we hold 65,000 net acres in the region with approximately 51,000 acres located in the liquids producing portions of the play.

The development of our assets in the Eagle Ford, which averaged approximately 47,500 Boe/d for the nine months ended September 30, 2013, an increase of 44% from the nine months ended September 30, 2012, has led to substantial growth for the Company, while shifting our portfolio toward higher-valued crude oil and NGL production. During 2012, we recorded a 35% increase in daily total equivalent production, with total liquids production growth of 76% and total proved reserves growth of 25% from 2011. At December 31, 2012, our total estimated proved reserves were 201 MMBoe, of which 58% were liquids. For the three and nine months ended September 30, 2013, approximately 65% and 63%, respectively, of our production was from liquids as compared to 60% and 57%, respectively, of our production from liquids for the same period in 2012. The Eagle Ford area accounted for approximately 97% of our total production for the nine months ended September 30, 2013. In addition, approximately 62% of the production from the Eagle Ford area in the nine months ended September 30, 2013 was from crude oil and NGLs.

We drilled 43 gross wells and completed 33 gross wells during the quarter ended September 30, 2013. Of these totals, 14 gross vertical wells were drilled in the Delaware Basin and 13 gross wells were completed, including 12 vertical and one horizontal well. As of September 30, 2013, we had completed a total of 180 gross wells in the Eagle Ford shale since entering the play. In the third quarter of 2013, total daily production increased 37% from the same period in 2012, and we recorded 4% growth from the prior quarter in total daily Company volumes. To handle our increased production, we have secured multiple options for transportation and processing capacity with firm commitments in place to meet total planned production levels through 2014, and we are evaluating adding more firm capacity in our operating areas.

With our purchase of the Permian Basin assets, we revised our capital guidance range upward from $640 $700 million to $840 $900 million, excluding capital used to fund the Permian Acquisition and Gates Acquisition. The 2013 capital program is based on a five to six-rig program in South Texas and an initial Delaware Basin program of three rigs increasing to six rigs by the end of the year. Our Delaware Basin rig count is currently at five rigs, up from three rigs as of the Permian Acquisition Date. We expect to spend approximately $600 million for development activities primarily located in the liquids-rich window of the Eagle Ford shale in South Texas, including about $55 million allocated to facilities projects. We expect to direct approximately $175 million toward operated and non-operated development activity in the oil-rich Delaware Basin in West Texas, including approximately $7 million for facilities projects. An additional $25 million of capitalized interest related to the Permian Acquisition has also been included in our revised budget. The remainder of our 2013 capital plan will be targeted to new ventures activity and other corporate capital requirements.

While our unconventional resource strategy has proven to be successful, we recognize that there are risks inherent to our industry that could impact our ability to meet future goals. Although we cannot completely control all external factors that could affect our operating environment, our business model takes into account the threats that could impede achievement of our stated growth objectives and the building of our asset base. We have diversified our production base to include a greater mix of crude oil and NGLs, which continue to be priced at more favorable levels than natural gas. Because our production is highly concentrated in the Eagle Ford and Permian Basin areas, we have taken various steps to provide access to necessary services and infrastructure. We believe that our 2013 capital program can be executed from internally generated cash flows, cash on hand, and drawing on unused capacity under our Credit Facility. We continuously monitor our liquidity to respond to changing market conditions, commodity prices and service costs. If our internal funds are insufficient to meet projected funding requirements, we would consider curtailing capital spending or accessing the capital markets.

Availability under our Credit Facility is restricted to a borrowing base, which is subject to review and adjustment on a semi-annual basis and other interim adjustments, including adjustments based on hedging arrangements and asset divestitures. The amount of the borrowing base is dependent on a number of factors, including our level of reserves, as well as the pricing outlook at the time of the redetermination. Subsequent to September 30, 2013, our semi-annual borrowing base redetermination was completed and our borrowing base under the Credit Facility was reconfirmed by our lenders at $800 million. As of October 31, 2013, we had $280 million of borrowings outstanding with $520 million available for borrowing under the Credit Facility.

Results of Operations

Revenues

Our consolidated financial statements for the three months ended September 30, 2013 reflect total revenues of $194.6 million (including derivative losses of $30.6 million) based on total volumes of 4.7 MMBoe. Our consolidated financial statements for the nine months ended September 30, 2013 reflect total revenues of $609.2 million (including derivative gains of $3.5 million) based on total volumes of 13.4 MMBoe.

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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	% Change Increase/ (Decrease)	2013	2012	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Revenues:						
Oil sales	$ 140,172	$ 92,377	52%	$ 353,119	$ 221,574	59%
NGL sales	50,857	35,179	45%	144,236	114,867	26%
Natural gas sales	34,136	23,019	48%	108,369	62,815	73%
Derivative instruments	(30,597)	(27,823)	10%	3,484	35,935	(90%)
Total revenues	$ 194,568	$ 122,752	59%	$ 609,208	$ 435,191	40%
Production:						
Oil (MBbls)	1,396.0	1,015.2	38%	3,622.3	2,422.7	50%
NGLs (MBbls)	1,649.5	1,036.3	59%	4,793.7	3,009.6	59%
Natural gas (MMcf)	9,843.4	8,162.8	21%	29,663.3	24,595.0	21%
Total equivalents (MBoe)	4,686.0	3,412.0	37%	13,359.9	9,531.4	40%
Average sales price:						
Oil, excluding derivatives (per Bbl)	$ 100.41	$ 90.99	10%	$ 97.48	$ 91.46	7%
Oil, including realized derivatives (per Bbl)	98.14	89.59	10%	95.71	90.35	6%
NGL, excluding derivatives (per Bbl)	30.83	33.95	(9%)	30.09	38.17	(21%)
NGL, including realized derivatives (per Bbl)	32.61	38.62	(16%)	32.19	39.98	(19%)
Natural gas, excluding derivatives (per Mcf)	3.47	2.82	23%	3.65	2.55	43%
Natural gas, including realized derivatives (per Mcf)	3.64	3.34	9%	3.76	3.13	20%
Revenue, excluding realized derivatives (per Boe)	48.05	44.13	9%	45.34	41.89	8%
Revenue, including realized derivatives (per Boe)	48.36	46.37	4%	45.85	43.66	5%

Oil sales. For the three and nine months ended September 30, 2013, oil sales, excluding derivative instruments, increased by $47.8 million and $131.5 million, respectively, from the same periods in 2012 due to higher oil production and higher realized prices. The increase in oil production for the three months ended September 30, 2013 was primarily attributable to our Gates Ranch and Reilly wells in the Eagle Ford area, whose combined total oil production was 9.7 MBbls per day, up from 6.1 MBbls per day in the comparable period, as well as oil production from our Permian Basin assets which contributed 1.7 MBbls per day in the current quarter. The increase in oil production for the nine months ended September 30, 2013 was primarily attributable to our Gates Ranch and Klotzman wells in the Eagle Ford area, whose combined total oil production was 9.4 MBbls per day, up from 7.7 MBbls per day in the comparable period, as well as oil production from our Permian Basin assets which contributed 1.0 MBbls per day in the current year.

Oil derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2013, realized oil derivative losses were $3.1 million and $6.4 million, respectively, compared to realized oil derivative losses of $1.4 million and $2.7 million for the three and nine months ended September 30, 2012, respectively.

NGL sales. For the three and nine months ended September 30, 2013, NGL sales, excluding derivative instruments, increased by $15.7 million and $29.4 million, respectively, from the same periods in 2012. The increase was attributable to increased production offset by lower average realized prices. The increase in NGL production was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total NGL production was 15.5 MBbls per day for the three months ended September 30, 2013, up from 9.2 MBbls per day in the comparable period, and 15.4 MBbls per day for the nine months ended September 30, 2013, up from 9.7 MBbls per day in the comparable period.

NGL derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2013, realized NGL derivative gains were $2.9 million and $10.1 million, respectively, compared to realized NGL derivative gains of $4.8 million and $5.5 million for the three and nine months ended September 30, 2012, respectively.

Natural gas sales. For the three and nine months ended September 30, 2013, natural gas sales, excluding derivative instruments, increased by $11.1 million and $45.6 million, respectively, from the same periods in 2012. The increase was primarily due to higher average realized prices and increased production. The increase in natural gas production was primarily attributable to our Gates Ranch wells in the Eagle Ford area, whose total natural gas production was 92.2 MMcf per day for the three months ended September 30, 2013, up from 73.8 MMcf per day in the comparable period, and 95.4 MMcf per day for the nine months ended September 30, 2013, up from 74.4 MMcf per day in the comparable period. The increase in natural gas production was partially reduced by the 2012 divestiture of our Lobo properties.

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Natural gas derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2013, realized natural gas derivative gains were $1.7 million and $3.1 million, respectively, compared to realized natural gas derivative gains of $4.2 million and $14.1 million for the three and nine months ended September 30, 2012, respectively.

Derivative instruments. Derivative instruments includes (i) unrealized derivative gains and losses due to changes in fair value of our commodity derivative contracts, (ii) unrealized derivative gains and losses due to the reclassification of commodity hedging gains and losses from Accumulated other comprehensive income as a result of discontinuing hedge accounting, and (iii) realized derivative gains and losses attributable to cash settlements associated with our commodity derivative contracts.

For the three and nine months ended September 30, 2013, Derivative instruments included (i) unrealized derivative losses of $32.2 million and $3.0 million, respectively, due to changes in fair value of our commodity derivative contracts, (ii) the reclassification of an unrealized derivative gain of $0.2 million and loss of $0.3 million, respectively, from Accumulated other comprehensive income, and (iii) realized derivative gains of $1.5 million and $6.8 million, respectively, from cash settlements.

For the three and nine months ended September 30, 2012, Derivative instruments included (i) an unrealized derivative loss of $36.4 million and unrealized derivative gain of $16.9 million, respectively, due to changes in fair value of our commodity derivative contracts, (ii) the reclassification of unrealized derivative gains of $1.0 million and $2.2 million, respectively, from Accumulated other comprehensive income, and (iii) realized derivative gains of $7.6 million and $16.9 million, respectively, from cash settlements.

Operating Expenses

The following table presents information regarding our operating expenses:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	**2012**	**% Change Increase/ (Decrease)**	**2013**	**2012**	**% Change Increase/ (Decrease)**
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Direct lease operating expense	$ 13,309	$ 9,416	41%	$ 32,718	$ 22,839	43%
Workover expense	2,141	80	2,576%	2,503	(142)	1,863%
Insurance expense	404	273	48%	761	767	(1%)
Production costs	$ 15,854	$ 9,769	62%	$ 35,982	$ 23,464	53%
Ad valorem taxes	3,109	928	235%	8,844	5,970	48%
Lease operating expense	$ 18,963	$ 10,697	77%	$ 44,826	$ 29,434	52%
Treating and transportation	18,807	12,807	47%	52,414	37,330	40%
Production taxes	4,787	5,402	(11%)	15,442	11,551	34%
	60,915	40,432	51%	153,382	107,328	43%

Depreciation, depletion and amortization (DD&A)						
General and administrative costs	18,790	19,972	(6%)	52,830	48,454	9%
Costs and expenses (per Boe of production)						
Production costs	$ 3.38	$ 2.86	18%	$ 2.69	$ 2.46	9%
Lease operating expense	4.05	3.14	29%	3.36	3.09	9%
Treating and transportation	4.01	3.75	7%	3.92	3.92	0%
Production taxes	1.02	1.58	(35%)	1.16	1.21	(4%)
Depreciation, depletion and amortization (DD&A)	13.00	11.85	10%	11.48	11.26	2%
General and administrative costs	4.01	5.85	(31%)	3.95	5.08	(22%)
General and administrative costs, excluding stock-based compensation	3.28	3.93	(17%)	3.33	3.82	(13%)

Lease operating expense. Lease operating expense increased $8.3 million and $15.4 million for the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012. For the three months ended September 30, 2013, the increase was a result of the Permian Acquisition, which represented $5.5 million of the increase, inclusive of $1.8 million of well workover costs, and increased Eagle Ford operations, which contributed $4.3 million of the increase. These increases were partially offset by a decline in costs of $1.5 million primarily due to divestitures of dry gas properties. For the nine months ended September 30, 2013, the increase was a result of increased Eagle Ford operations, which contributed $16.0 million of the increase, and the result of the Permian Acquisition, which represented $8.1 million of the increase, inclusive of $1.8 million of well workover costs. These increases were partially offset by a decline in costs of $8.7 million primarily due to divestitures of dry gas properties.

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Treating and transportation. Treating and transportation expense increased $6.0 million and $15.1 million for the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. For the three and nine months ended September 30, 2013, the increases were a result of increased daily production of 33% and 44%, respectively, in the Eagle Ford shale as well as higher unit costs required to transport incremental production from the area. Additionally, we have accrued deficiency fees of $2.7 million and $6.5 million related to shortfalls in delivering the minimum volumes required under our transportation and processing agreements during the three and nine months ended September 30, 2013, respectively.

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 2.1% and 2.5% for the three and nine months ended September 30, 2013 compared to 3.6% and 2.9%, respectively, for the same periods in 2012. The decrease in rates is due to certain production tax credits received in the three and nine months ended September 30, 2013 primarily associated with our production in the State of Texas.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $20.5 million and $46.1 million for the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. The increases were a result of increased daily production of 37% and 41%, respectively, as well as an increased depletion rate due to the inclusion of higher-cost Permian reserves in our depletion pool.

General and administrative costs. General and administrative costs decreased $1.2 million and increased $4.4 million for the three and nine months ended September 30, 2013, respectively, as compared to the same periods in 2012. The decrease for the three months ended September 30, 2013 was primarily due to a $3.2 million decrease in stock-based compensation expense, partially offset by a $1.8 million increase in personnel costs and a $0.2 million increase in other general and administrative expenses. The increase for the nine months ended September 30, 2013 was primarily due to $2.3 million in transaction costs associated with the Permian Acquisition, a $5.4 million increase in personnel costs and $0.4 million in other general and administrative expenses, partially offset by a $3.7 million decrease in stock-based compensation expense.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other expense (income), net, increased $1.5 million and $9.1 million for the three and nine months ended September 30, 2013, respectively, compared to the same periods in 2012. The increase for the three months ended September 30, 2013 was primarily due to an increase in debt outstanding compared to the prior comparable period, partially offset by higher capitalized interest. The increase for the nine months ended September 30, 2013 was primarily due to $5.6 million in Bridge Credit Facility fees, which were expensed in the second quarter of 2013 as we did not borrow under our Bridge Credit Facility to help fund the Permian Acquisition. In addition, there was an increase in debt outstanding compared to the prior comparable period, partially offset by higher capitalized interest. The weighted average interest rate for the three and nine months ended September 30, 2013 was 5.77% and 5.95%, respectively, compared to 6.52% and 7.65%, respectively, for the same periods in 2012.

Provision for Income Taxes

The effective tax rate for the three and nine months ended September 30, 2013 was 36.7% and 35.5%, respectively compared to 35.5% and 36.1%, respectively, for the prior comparable periods. The provision for income taxes for the three and nine months ended September 30, 2013 differs from the tax computed at the federal statutory income tax rate primarily due to the effects of state taxes and the non-deductibility of certain incentive compensation. In addition, during the first quarter of 2013 there was a one-time favorable discrete adjustment of (2.9%) to reflect a change in the amount of deductible executive compensation. Excluding discrete items, the effective tax rate for the nine months ended September 30, 2013 was 36.3%, and the rate applicable to future earnings is expected to be consistent with that rate. As of September 30, 2013 and December 31, 2012, we had no unrecognized tax benefits and we do not anticipate that total unrecognized tax benefits will significantly change due to the settlement of audits or the expiration of statute of limitations within the next twelve months.

We provide for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. Considerable judgment is required in determining when these events may occur and whether recovery of an asset is more likely than not. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2013, we had a net deferred tax liability of $92.8 million resulting primarily from differences between the book basis and tax basis of our oil and natural gas properties, partially offset by net operating loss carryforwards.

Liquidity and Capital Resources

Our sources of liquidity and capital are our operating cash flow, cash on hand and our Credit Facility, which can be accessed as needed to supplement operating cash flow.

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

Cash Flows

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

	Nine Months Ended September 30, 2013	2012
	(In thousands)	
Cash provided by (used in):		
Operating activities	$ 469,423	$ 259,290
Investing activities	(1,522,245)	(370,034)
Financing activities	1,079,992	112,871
Net increase in cash and cash equivalents	$ 27,170	$ 2,127

Operating Activities. Net cash provided by operating activities for the nine months ended September 30, 2013 compared to the same period in 2012 reflects higher operating income in 2013 as a result of increased production and an expansion of 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.

Investing Activities. Net cash used in investing activities for the nine months ended September 30, 2013 compared to the same period in 2012 reflects our Permian Acquisition and our Gates Acquisition, as well as higher capital spending related to our Eagle Ford drilling program and the initial funding of our development program in the Permian Basin.

Financing Activities. Net cash provided by financing activities for the nine months ended September 30, 2013 compared to the same period in 2012 reflects our $700 million issuance of the 5.625% Senior Notes and associated debt issuance costs, our equity issuance of 8.05 million common shares, and net borrowings of $65.0 million under the Credit Facility in 2013.

Capital Expenditures and Requirements

Our historical capital expenditures summary table is included in Items 1 and 2. Business and Properties in our 2012 Annual Report and is incorporated herein by reference.

Our capital expenditures, excluding the impact of $952.7 million already incurred related to the Permian Acquisition and Gates Acquisition, for the nine months ended September 30, 2013 increased by $113.5 million to $606.0 million from $492.5 million for the nine months ended September 30, 2012. During the nine months ended September 30, 2013, we drilled 97 and completed 72 gross wells, the majority of which were located in the Eagle Ford area. Excluding capital used to fund the Permian Acquisition and Gates Acquisition, our capital budget for 2013 is projected to be approximately $840 to $900 million compared to our previous budget range of $640 to $700 million. The increase in our capital budget is driven by our drilling program for the remainder of the year associated with our Permian Basin assets that we acquired in May 2013.

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

Fair Value of Financial Instruments

The energy markets have historically been very volatile and oil, NGL and natural gas prices will be subject to wide fluctuations in the future. To mitigate our exposure to changes in commodity prices, management hedges oil, NGL and natural gas prices from time to time, primarily through the use of certain derivative instruments, including fixed price swaps, basis swaps, NYMEX roll swaps, costless collars and put options. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow to fund our capital program. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps, basis swaps, NYMEX roll swaps and costless collars for each year through 2015. Our fixed price swap, basis swap, NYMEX roll swap and costless collar agreements require payments to (or receipts from) counterparties based on the differential between a fixed price and a variable price for a notional quantity of oil, NGLs and natural gas, as applicable, without the exchange of underlying volumes. The notional amounts of these financial instruments were based on a portion of our expected production from existing wells upon inception of the derivative instruments. See Note 4 Commodity Derivative Contracts and Note 5 Fair Value Measurements included in Part I. Item 1. Financial Statements of this Form 10-Q for a listing of open contracts as of September 30, 2013, a description of the applicable accounting and the estimated fair market values as of September 30, 2013. The effects of material changes in market risk exposure associated with these derivative transactions are discussed below under Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Governmental Regulation

There have been no material changes in governmental regulations that impact our business from those previously disclosed in our 2012 Annual Report.

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 2012 Annual Report.

Recent Accounting Developments

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

Commitments and Contingencies

As is common within the oil and natural gas industry, we have entered into various commitments and operating agreements related to the exploration and development of and production from proved oil and natural gas properties. It is our belief that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

As noted in Note 9 Commitments and Contingencies included in Part I. Item 1. Financial Statements of this Form 10-Q, we forecast long-term production from the development of our reserves in the Eagle Ford area. These forecasts are used to identify our future transportation and processing volume requirements. Based on these forecasts, we have secured additional firm capacity for the transportation and processing of our production in the Eagle Ford area. These commitments are typically effective prior to us having sufficient current production to meet the minimum volume commitments and we are therefore required to make periodic deficiency payments for delivering less than the minimum required volumes, as is the case through the first nine months of 2013. As we develop our reserves in the Eagle Ford area, we anticipate exceeding our current minimum volume commitments and we therefore intend to enter into additional transportation and processing commitments in the future. These future transportation and processing commitments could expose us to additional volume deficiency payments as we further develop our Eagle Ford assets. As of September 30, 2013, we had accrued deficiency fees of $6.5 million. We expect to continue to accrue additional deficiency fees under our current and future commitments.

We are party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. We have evaluated the need for a reserve for each respective matter in accordance with applicable accounting guidance and recorded a $0.5 million reserve related to a commercial dispute, which is included in Other expense (income), net in the Consolidated Statement of Operations for the three and nine months ended September 30, 2013 and Accrued liabilities in the Consolidated Balance Sheet as of September 30, 2013. The outcomes of all remaining matters are not known and the related damages, if any, cannot be reasonably estimated at this time. We intend to vigorously defend our position in all such disputes; however, it is remotely possible that an adverse decision or settlement of one or more of such matters could have a material effect on us, our financial condition, results of operations and cash flows.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to market risk primarily related to adverse changes in oil, NGL and natural gas prices. We use derivative instruments to manage our commodity price risk caused by fluctuating prices. We do not enter into derivative instruments for trading purposes. For information regarding our exposure to certain market risks, see Item 7A. Quantitative and Qualitative Disclosures about Market Risk in our 2012 Annual Report and Note 4 Commodity Derivative Contracts included in Part I. Item 1. Financial Statements of this Form 10-Q.

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As of September 30, 2013, we had open crude oil derivative contracts in a net liability position with a fair value of $6.1 million. A 10% increase in crude oil prices would reduce the fair value by approximately $52.7 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $50.2 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of September 30, 2013, we had open NGL derivative contracts in a net asset position with a fair value of $10.7 million. A 10% increase in NGL prices would reduce the fair value by approximately $9.2 million, while a 10% decrease in NGL prices would increase the fair value by approximately $9.2 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

As of September 30, 2013, we had open natural gas derivative contracts in a net asset position with a fair value of $13.0 million. A 10% increase in natural gas prices would reduce the fair value by approximately $18.3 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $19.6 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations Revenues.

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

As of September 30, 2013, the Company s derivative instruments are with counterparties who are lenders under the Company s Credit Facility. This practice 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 Facility, thus eliminating the need for independent collateral postings. As of September 30, 2013, 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 future market prices on hedged volumes of the commodities as of September 30, 2013. Our third-party provider evaluated non-performance risk using the current credit default swap values or bond spreads for both the counterparties and us. We recorded a downward adjustment to the fair value of our derivative instruments in the amount of $0.1 million as of September 30, 2013. We currently do not know of any current circumstances that would limit access to our Credit Facility or require a change in our debt or hedging structure.

We entered into oil, NGL and natural gas derivative contracts with respect to a portion of our expected production through 2015. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices were to exceed the price established by the contract. As of September 30, 2013, 97% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 3% at Light Louisiana Sweet (LLS); 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 58% of our natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel, 29% at Tennessee, zone 0 and the remaining 13% at Henry Hub.

We use a third-party provider to determine the valuation of our derivative instruments and compare the fair values derived from the third-party provider with values provided by our counterparties. We mark-to-market the fair values of our derivative instruments on a quarterly basis and 100% of our derivative assets and liabilities are considered Level 3 instruments.

Item 4. Controls and Procedures

Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act, as of September 30, 2013. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2013, our disclosure controls and procedures were effective in providing reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to the Company s management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

There were no changes in our internal control over financial reporting that occurred during the three months ended September 30, 2013 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

See Part I, Item 1, Note 9 - Commitments and Contingencies of this Form 10-Q, which is incorporated in this item by reference.

Item 1A. Risk Factors

There have been no material changes in our risk factors from those previously disclosed in Item 1A. of our 2012 Annual Report and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2013.

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 September 30, 2013:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
July 1 - July 31	1,010	$ 42.72		
August 1 - August 31	689	47.11		
September 1 - September 30	827	46.85		
Total	2,526	$ 45.27		

(1) All of the shares were surrendered by our employees and certain of our directors to pay tax withholding upon the vesting of restricted stock awards. We do not 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
2.2	Purchase and Sale Agreement with Comstock Oil & Gas, LP dated March 14, 2013 (incorporated herein by reference to Exhibit 2.2 of the Company s Current Report on Form 10-Q filed on May 6, 2013 (Registration No. 000-51801)).
4.1	Indenture, dated as of May 2, 2013, between Rosetta Resources Inc., as issuer, and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.1 of the Company s Current Report on Form 8-K filed on May 2, 2013 (Registration No. 000-51801)).
4.2	First Supplemental Indenture, dated as of May 2, 2013, among Rosetta Resources Inc., as issuer, the Subsidiary Guarantors named therein, as guarantors, and Wells Fargo Bank, National Association, as trustee (incorporated herein by reference to Exhibit 4.2 of the Company s Current Report on Form 8-K filed on May 2, 2013 (Registration No. 000-51801)).
10.52	Sixth Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of April 12, 2013, 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 10.52 to the Company s Current Report on Form 8-K filed on April 15, 2013 (Registration No. 000-51801)).
10.53*	Seventh Amendment to Amended and Restated Senior Revolving Credit Agreement, effective as of July 30, 2013, among Rosetta Resources Inc., as borrower, Wells Fargo Bank, National Association, as administrative agent, and the lenders signatory thereto (attached hereto as Exhibit 10.53).
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Filed herewith

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SIGNATURES

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

ROSETTA RESOURCES INC.

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

Executive Vice President and Chief Financial Officer

(Duly Authorized Officer and Principal Financial Officer)

Date: November 6, 2013