Rosetta Resources Inc.
Form 10-Q
November 03, 2014

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, 2014

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 (State or other jurisdiction of incorporation or organization)	43-2083519 (I.R.S. Employer Identification No.)
1111 Bagby Street, Suite 1600	
Houston, TX (Address of principal executive offices)	77002 (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 24, 2014 was 61,489,705 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, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$23,627	$193,784
Accounts receivable	154,268	122,677
Derivative instruments	14,249	4,307
Prepaid expenses	9,050	9,860
Deferred income taxes	1,524	27,976
Other current assets	5,032	1,284
Total current assets	207,750	359,888
Oil and natural gas properties using the full cost method of accounting:		
Proved properties	5,172,365	3,951,397
Unproved/unevaluated properties, not subject to amortization	535,041	755,438
Gathering systems and compressor stations	278,045	168,730
Other fixed assets	29,794	26,362
	6,015,245	4,901,927
Accumulated depreciation, depletion and amortization, including impairment	(2,313,109)	(2,020,879)
Total property and equipment, net	3,702,136	2,881,048
Other assets:		
Debt issuance costs	26,756	25,602
Derivative instruments	8,347	5,458
Other long-term assets	281	4,622
Total other assets	35,384	35,682
Total assets	$3,945,270	$3,276,618
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$236,058	$190,950
Royalties and other payables	114,164	78,264
Derivative instruments	—	4,913
Total current liabilities	350,222	274,127
Long-term liabilities:		
Derivative instruments	966	433
Long-term debt	1,910,000	1,500,000
Deferred income taxes	179,833	136,407

Other long-term liabilities	19,705	17,317
Total liabilities	2,460,726	1,928,284
Commitments and Contingencies (Note 9)		
Stockholders' equity:		
Preferred stock, $0.001 par value; authorized 5,000,000 shares; no shares issued in 2014 or 2013	—	—
Common stock, $0.001 par value; authorized 150,000,000 shares; issued 62,272,702 shares and 62,032,162 shares at September 30, 2014 and December 31, 2013, respectively	62	61
Additional paid-in capital	1,193,492	1,182,672
Treasury stock, at cost; 785,185 shares and 724,755 shares at September 30, 2014 and December 31, 2013, respectively	(27,308)	(24,592)
Accumulated other comprehensive loss	(98)	(108)
Retained earnings	318,396	190,301
Total stockholders' equity	1,484,544	1,348,334
Total liabilities and stockholders' equity	$3,945,270	$3,276,618

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Operations

(In thousands, except per share amounts)

(Unaudited)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Revenues:				
Oil sales	$168,016	$140,172	$462,396	$353,119
NGL sales	66,003	50,857	176,740	144,236
Natural gas sales	54,359	34,136	157,878	108,369
Derivative instruments	77,215	(30,597)	4,035	3,484
Total revenues	365,593	194,568	801,049	609,208
Operating costs and expenses:				
Lease operating expense	26,952	15,854	71,537	35,982
Treating and transportation	23,638	18,807	62,933	52,414
Taxes, other than income	13,191	7,896	35,656	24,286
Depreciation, depletion and amortization	128,255	60,915	293,670	153,382
Reserve for commercial disputes	5,800	—	5,800	—
General and administrative costs	23,438	18,790	64,643	52,830
Total operating costs and expenses	221,274	122,262	534,239	318,894
Operating income	144,319	72,306	266,810	290,314
Other expense (income):				
Interest expense, net of interest capitalized	21,011	6,907	53,628	26,009
Interest income	(1)	—	(14)	—
Other expense	(116)	620	12,531	1,061
Total other expense	20,894	7,527	66,145	27,070
Income before provision for income taxes	123,425	64,779	200,665	263,244
Income tax expense	45,017	23,754	72,570	93,387
Net income	$78,408	$41,025	$128,095	$169,857
Earnings per share:				
Basic	$1.28	$0.67	$2.08	$2.95
Diluted	$1.27	$0.67	$2.08	$2.93
Weighted average shares outstanding:				
Basic	61,484	61,152	61,439	57,656
Diluted	61,675	61,364	61,636	57,924

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,	
	2014	2013	2014	2013
Net income	$78,408	$41,025	$128,095	$169,857
Other comprehensive income (loss):				
Amortization of accumulated other comprehensive gain (loss) related to de-designated hedges, net of income taxes of $58 and ($97) for the three and nine months ended September 30, 2013, respectively	—	(102)	—	171
Postretirement medical benefits prior service benefit (cost), net of income taxes of ($2) and ($3) for the three months ended September 30, 2014 and 2013, respectively, and ($6) and $98 for the nine months ended September 30, 2014 and 2013, respectively	4	6	10	(173)
Other comprehensive income (loss)	4	(96)	10	(2)
Comprehensive income	$78,412	$40,929	$128,105	$169,855

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Cash Flows

(In thousands)

(Unaudited)

	Nine Months Ended September 30, 2014	2013
Cash flows from operating activities:		
Net income	$128,095	$169,857
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	293,670	153,382
Deferred income taxes	69,914	89,358
Amortization of deferred loan fees recorded as interest expense	2,866	7,674
Loss on debt extinguishment	3,101	—
Stock-based compensation expense	9,821	8,293
(Gain) loss due to change in fair value of derivative instruments	(17,211)	3,280
Change in operating assets and liabilities:		
Accounts receivable	(31,592)	(11,230)
Prepaid expenses	2,053	(652)
Other current assets	(3,749)	171
Long-term assets	90	(105)
Accounts payable and accrued liabilities	17,848	32,347
Royalties and other payables	35,899	19,201
Other long-term liabilities	(14)	4,189
Excess tax benefit from share-based awards	—	(6,342)
Net cash provided by operating activities	510,791	469,423
Cash flows from investing activities:		
Acquisitions of oil and gas assets	(79,600)	(952,703)
Additions to oil and gas assets	(1,000,816)	(568,140)
Disposals of oil and gas assets	8	(1,402)
Net cash used in investing activities	(1,080,408)	(1,522,245)
Cash flows from financing activities:		
Borrowings on Credit Facility	795,000	580,000
Payments on Credit Facility	(685,000)	(515,000)
Issuance of Senior Notes	500,000	700,000
Retirement of Senior Notes	(200,000)	—
Proceeds from issuance of common stock	—	329,008
Deferred loan fees	(8,364)	(18,102)
Proceeds from stock options exercised	375	4,582
Purchases of treasury stock	(2,716)	(6,838)
Excess tax benefit from share-based awards	165	6,342
Net cash provided by financing activities	399,460	1,079,992
Net (decrease) increase in cash	(170,157)	27,170
Cash and cash equivalents, beginning of period	193,784	36,786
Cash and cash equivalents, end of period	$23,627	$63,956

Supplemental disclosures:		
Capital expenditures included in Accounts payable and accrued liabilities	$145,956	$126,780

See accompanying notes to the consolidated financial statements.

Rosetta Resources Inc.

Consolidated Statement of Stockholders' Equity

(In thousands, except share amounts)

(Unaudited)

	Common Stock		Additional	Treasury Stock		Accumulated Other		Total Stockholders'
	Shares	Amount	Paid-In Capital	Shares	Amount	Comprehensive Loss	Retained Earnings	Equity
Balance at December 31, 2013	62,032,162	$ 61	$ 1,182,672	724,755	$ (24,592)	$ (108)	$ 190,301	$ 1,348,334
Excess tax benefit from share-based awards	—	—	165	—	—	—	—	165
Stock options exercised	19,000	1	375	—	—	—	—	376
Treasury stock - employee tax payment	—	—	—	60,430	(2,716)	—	—	(2,716)
Stock-based compensation	—	—	10,280	—	—	—	—	10,280
Vesting of restricted stock	221,540	—	—	—	—	—	—	—
Comprehensive income	—	—	—	—	—	10	128,095	128,105
Balance at September 30, 2014	62,272,702	$ 62	$ 1,193,492	785,185	$ (27,308)	$ (98)	$ 318,396	$ 1,484,544

See accompanying notes to the consolidated financial statements.

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 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, 2013 ("2013 Annual Report").

(2) Summary of Significant Accounting Policies

The Company has provided a discussion of significant accounting policies, estimates and judgments in its 2013 Annual Report. There have been no changes to the Company's significant accounting policies since December 31, 2013.

Recent Accounting Developments

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, Revenue from Contracts with Customers. The ASU will supersede most of the existing revenue recognition requirements in GAAP and will require entities to recognize revenue at an amount that reflects the consideration to which the company expects to be entitled in exchange for transferring goods or services to a customer. The new standard also requires disclosures sufficient to enable users to understand an entity's nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The pronouncement is effective for annual and interim reporting periods beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted. This guidance is not expected to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

(3) Property and Equipment

The Company's Total property and equipment, net consists of the following:

	September 30, 2014	December 31, 2013
	(In thousands)	
Proved properties	$5,172,365	$3,951,397
Unproved/unevaluated properties	535,041	755,438
Gathering systems and compressor stations	278,045	168,730
Other fixed assets	29,794	26,362
Total	6,015,245	4,901,927
Less: Accumulated depreciation, depletion and amortization	(2,313,109)	(2,020,879)
Total property and equipment, net	$3,702,136	$2,881,048

Acquisitions

2014 Permian Acquisition. On December 30, 2013, the Company entered into a definitive agreement with several private parties to acquire Delaware Basin assets covering 5,034 net acres located in Reeves County (the “2014 Permian Acquisition”). These assets include 13 gross producing wells, of which 11 are operated by the Company. The Company completed the 2014 Permian Acquisition on February 28, 2014, with an effective date of December 1, 2013, for total cash consideration of $83.8 million.

Gates Ranch Acquisition. In the second quarter of 2013, the Company acquired the remaining 10% working interest in certain producing wells along with a third party's option to participate in future wells in certain leases of its Gates Ranch leasehold located in the Eagle Ford shale (the "Gates Acquisition") in Webb County 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 senior secured revolving credit facility (the "Credit Facility"), as described in Note 7 – Debt and Credit Agreements. As of the Gates Acquisition Date, the Company owns a 100% working interest in the entire Gates Ranch leasehold.

2013 Permian Acquisition. On March 14, 2013, the Company entered into a purchase and sale agreement with Comstock Oil & Gas, LP to purchase producing and undeveloped oil and natural gas interests in the Permian Basin in Gaines and Reeves Counties, Texas (the "2013 Permian Acquisition"). The Company completed the 2013 Permian Acquisition on May 14, 2013, with an effective date of January 1, 2013, for total cash consideration of $825.2 million. The 2013 Permian Acquisition was financed with the proceeds from the Company's issuance of the 5.625% Senior Notes, as described in Note 7 – Debt and Credit Agreements, and the common stock offering described in Note 10 – Equity. In connection with the 2013 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.

The above transactions were accounted for under the acquisition method of accounting, whereby each respective 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 final purchase price allocations for these acquisitions, no goodwill or bargain purchase was recognized. The final purchase price allocations for these transactions, representing consideration paid, assets acquired and liabilities assumed as of the respective acquisition dates, are shown in the tables below.

2014 Permian Acquisition

	Final Total Purchase Price Allocation (In thousands)
Cash consideration	$ 83,752
Fair value of assets acquired:	
Oil and natural gas properties	
Proved properties	$ 61,520
Unproved/unevaluated properties	22,525
Total assets acquired	$ 84,045
Fair value of liabilities assumed:	
Asset retirement obligations	$ 293
Net assets acquired	$ 83,752

2013 Permian Acquisition and Gates Ranch Acquisition

	Final Total Purchase Price Allocation (In thousands)
Cash consideration	$ 953,242
Fair value of assets acquired:	
Other fixed assets	$ 600
Oil and natural gas properties	
Proved properties	290,273
Unproved/unevaluated properties	663,300
Total assets acquired	$ 954,173
Fair value of liabilities assumed:	
Asset retirement obligations	$ 931
Net assets acquired	$ 953,242

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) future production, including adjustments for risk; (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. See Note 5 – Fair Value Measurements for additional information.

The results of operations attributable to the 2014 Permian Acquisition were included in the Company's Consolidated Statement of Operations beginning on March 1, 2014 and increased Total revenues by $3.3 million and $9.2 million, respectively, and Operating income by $0.9 million and $3.2 million, respectively, for the three and nine months ended September 30, 2014.

The following unaudited pro forma information assumes the transactions and related financings for the 2013 Permian Acquisition and the Gates Acquisition occurred on January 1, 2012 and the 2014 Permian Acquisition occurred on January 1, 2013. The unaudited pro forma information includes the effects of issuing 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 as discussed above. 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 sellers, the Company's knowledge of the acquired properties and the impact of the Company's purchase price allocation. The Company believes the assumptions used provide a reasonable basis for reflecting 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 acquisitions, or any estimated costs that have been or will be incurred by the Company to integrate these assets. The pro forma information does not purport to represent what the Company's results of operations would have been if the 2013 Permian Acquisition and Gates Acquisition had occurred on January 1, 2012, and the 2014 Permian Acquisition had occurred on January 1, 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014 (1)	2013 (2)	2014 (2)	2013
	(In thousands, except per share and share data)		(In thousands, except per share and share data)	
Total revenues	$365,593	$200,525	$804,146	$658,037
Net income	78,408	43,284	128,840	185,049
Earnings per share:				
Basic	$1.28	$0.71	$2.10	$3.03
Diluted	$1.27	$0.71	$2.09	$3.02
Weighted average shares outstanding:				
Basic	61,484	61,152	61,439	61,011
Diluted	61,675	61,364	61,636	61,279

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

(2)

No pro forma adjustments were made related to the 2013 Permian Acquisition and Gates Acquisition for the period as the acquisitions 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 $1.9 million and $1.6 million of internal costs for the three months ended September 30, 2014 and 2013, respectively, and $5.6 million and $5.5 million for the nine months ended September 30, 2014 and 2013, respectively.

Oil and gas properties include unevaluated property costs of $535.0 million and $755.4 million as of September 30, 2014 and December 31, 2013, 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. Such costs are periodically evaluated for impairment, and upon evaluation or impairment are transferred to the Company's full cost pool and amortized. During the nine months ended September 30, 2014, the Company transferred $162.9 million of Permian acquisition costs to the full cost pool as a result of development activities in this area.

Pursuant to full cost accounting rules, the Company must perform a ceiling test each quarter on its proved oil and natural gas assets within each separate cost center. All of the Company's costs are included in one cost center because all of the Company's operations are located in the United States. The Company's ceiling test was calculated using trailing twelve-month, unweightedaverage first-day-of-the-month prices for oil and natural gas as of September 30, 2014, which were based on a West Texas Intermediate oil price of $95.56 per Bbl and a Henry Hub natural gas price of $4.24 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 of September 30, 2014, and as a result, no write-down was recorded. 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 significantly 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 and costless collars. Forward contracts on various commodities are entered into to manage the price risk associated with forecasted sales of the Company's oil, NGL and natural gas production.

As of September 30, 2014, 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 (Bbls)	Total Notional Volume (Bbls)	Average Floor/Fixed Prices per Bbl	Average Ceiling Prices per Bbl
Crude oil	2014	Costless Collar	3,000	276,000	$ 83.33	$ 109.63
Crude oil	2014	Swap	6,000	552,000	93.13	
Crude oil	2015	Swap	12,000	4,380,000	89.81	
Crude oil	2016	Swap	6,000	2,196,000	90.28	
				7,404,000		

Product	Settlement Period	Derivative Instrument	Notional Daily Volume (Bbls)	Total Notional Volume (Bbls)	Average Fixed Prices per Bbl
NGL-Ethane	2014	Swap	4,500	414,000	$ 13.21
NGL-Propane	2014	Swap	2,785	256,220	44.71
NGL-Isobutane	2014	Swap	930	85,560	61.26
NGL-Normal Butane	2014	Swap	875	80,500	60.29
NGL-Pentanes Plus	2014	Swap	910	83,720	84.97
NGL-Ethane	2015	Swap	3,476	1,268,810	11.31

NGL-Propane	2015	Swap	1,750	638,750	43.35
NGL-Isobutane	2015	Swap	617	225,082	53.05
NGL-Normal Butane	2015	Swap	579	211,179	52.53
NGL-Pentanes Plus	2015	Swap	579	211,179	77.72
				3,475,000	

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	2014	Costless Collar	50,000	4,600,000	3.60	4.94
Natural gas	2015	Costless Collar	50,000	18,250,000	3.60	5.04
Natural gas	2016	Costless Collar	40,000	14,640,000	3.50	5.58
Natural gas	2014	Swap	30,000	2,760,000	4.07	
Natural gas	2015	Swap	50,000	18,250,000	4.13	
Natural gas	2016	Swap	30,000	10,980,000	4.04	
				69,480,000		

As of September 30, 2014, the Company's derivative instruments were with counterparties who are lenders under its Credit Facility. This practice allows the Company to satisfy any need for margin obligations resulting from an adverse change in the fair market value of its derivative contracts with the collateral securing its Credit 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 2013 Annual Report. As of September 30, 2014, the Company had no deposits for collateral regarding commodity derivative positions.

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 discontinue hedge accounting prospectively. As of December 31, 2013, all frozen mark-to-market values included in Accumulated other comprehensive income were reclassified into earnings. With the election to de-designate hedging instruments, all of the Company's derivative instruments are 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 have 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 derivative guidance 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, 2014 and December 31, 2013, respectively:

	Asset (Liability) Fair Value	
	September 30,	December 31, 2013

Commodity derivative contracts	Location on Consolidated Balance Sheet	2014 (In thousands)	
Oil	Derivative instruments - current assets	$5,853	$ 1,299
Oil	Derivative instruments - non-current assets	6,895	2,117
Oil	Derivative instruments - current liabilities	—	(5,629)
Oil	Derivative instruments - non-current liabilities	(545)	—
NGL	Derivative instruments - current assets	4,675	2,834
NGL	Derivative instruments - non-current assets	199	(129)
NGL	Derivative instruments - current liabilities	—	461
NGL	Derivative instruments - non-current liabilities	—	(433)
Natural gas	Derivative instruments - current assets	3,721	174
Natural gas	Derivative instruments - non-current assets	1,253	3,470
Natural gas	Derivative instruments - current liabilities	—	255
Natural gas	Derivative instruments - non-current liabilities	(421)	—
Total derivative fair value, net, not designated as hedging instruments		$21,630	$ 4,419

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The following table sets forth information on the location and amounts of derivative gains and losses in the Consolidated Statement of Operations for the three and nine months ended September 30, 2014 and 2013, respectively:

Location on Consolidated Statement of Operations	Description of (Loss) Gain	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
		(In thousands)			
Derivative instruments	Gain (loss) recognized in income	475	1,473	(13,176)	6,764
	Realized gain (loss) recognized in income	$475	$1,473	$(13,176)	$6,764
Derivative instruments	Gain (loss) recognized in income due to changes in fair value	$76,740	$(32,229)	$17,211	$(3,012)
Derivative instruments	Gain (loss) reclassified from Accumulated OCI	—	159	—	(268)
	Unrealized gain (loss) recognized in income	$76,740	$(32,070)	$17,211	$(3,280)
	Total commodity derivative gain (loss) recognized in income	$77,215	$(30,597)	$4,035	$3,484

(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. See Note 3 – Property and Equipment for more information on the Company's fair value measurement of non-recurring assets and liabilities related to the 2014 Permian Acquisition.

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

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

- "Level 1" inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- "Level 2" inputs are quoted prices for similar assets and liabilities in active markets or inputs that are observable for the asset or liability, either directly or indirectly through market corroboration, for substantially the full term of the financial instrument.
- "Level 3" inputs are measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources.

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, 2014				
	Level 1	Level 2	Level 3	Netting (1)	Total
	(In thousands)				
Assets:					
Money market funds	$—	$1,035	$—	$—	$1,035
Commodity derivative contracts	—	—	29,724	(7,128)	22,596
Liabilities:					
Commodity derivative contracts	—	—	(8,094)	7,128	(966)
Total fair value	$—	$1,035	$21,630	$—	$22,665

	Fair value as of December 31, 2013				
	Level 1	Level 2	Level 3	Netting (1)	Total
	(In thousands)				
Assets:					
Money market funds	$—	$1,035	$—	$—	$1,035
Commodity derivative contracts	—	—	21,675	(11,910)	9,765
Liabilities:					
Commodity derivative contracts	—	—	(17,256)	11,910	(5,346)
Total fair value	$—	$1,035	$4,419	$—	$5,454

(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.

The following table presents a range of the unobservable inputs provided by the Company's 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, 2014 (in thousands):

Level 3 Instrument	Asset (Liability) (In thousands)	Valuation Technique	Unobservable Input	Range Minimum	Range Maximum	Weighted Average
Oil swaps	$ 12,042	Discounted cash flow	Forward price curve-swaps	$85.30	$ 92.73	$ 88.51
Oil costless collars	161	Option model	Forward price curve-costless collar option value	(0.12)	1.40	(0.58)
NGL swaps	5,006	Discounted cash flow	Forward price curve-swaps	0.24	1.95	0.76
NGL swaps	(132)	Discounted cash flow	Forward price curve-swaps	1.83	1.93	1.87
Natural gas swaps	2,453	Discounted cash flow	Forward price curve-swaps	(0.02)	4.35	4.05
Natural gas swaps	(1,120)	Discounted cash flow	Forward price curve-swaps	4.01	4.35	4.15
Natural gas costless collars	3,220	Option model	Forward price curve-costless collar option value	(0.22)	0.37	(0.09)
Total	$ 21,630					

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, 2014.

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) (In thousands)
Balance at January 1, 2014	$ 4,419
Total Gains (Realized or Unrealized):	
Included in Earnings	4,035
Purchases, Issuances and Settlements:	
Settlements	13,176
Transfers in and out of Level 3	—
Balance at September 30, 2014	$ 21,630

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

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, 2014, the carrying value of cash and cash equivalents (excluding money market funds), other current assets and current liabilities reported in the Consolidated Balance Sheet approximate fair value because of their short-term nature, and all such financial instruments are considered Level 1 instruments.

The Company’s debt consists of publicly traded Senior Notes (defined below) and borrowings under the Credit Facility (defined below). The fair values of the Company’s 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, 2014, the carrying amount of total debt was $1.91 billion and the estimated fair value of total debt was $1.89 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, 2014 (In thousands)
ARO as of December 31, 2013	$ 13,057
Liabilities incurred during period	2,807
Liabilities settled during period	(1,347)
Accretion expense	741
ARO as of September 30, 2014	$ 15,258

As of September 30, 2014, the $4.0 million current portion of the total ARO is included in Accrued liabilities, and the $11.3 million long-term portion of ARO is included in Other long-term liabilities on the Consolidated Balance Sheet.

(7) Debt and Credit Agreements

Senior Secured Revolving Credit Facility. On April 2, 2014, the Company entered into the Omnibus Eighth Amendment to 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) authorized the redemption of the Company’s 9.500% Senior Notes due 2018 (the “9.500% Senior Notes”), (ii) increased the borrowing base from $800.0 million to

$950.0 million and (iii) reconfirmed the committed amount under the Credit Facility at $800 million with a maximum credit amount of $1.5 billion. On September 30, 2014, the Company's semi-annual borrowing base redetermination was completed and the borrowing base and committed amounts under the Credit Facility were reconfirmed by the lenders at $950.0 million and $800.0 million, respectively.

As of September 30, 2014, the Company had $110.0 million outstanding with $690.0 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% and mature in April 2018. Additionally, the Company can borrow under the Credit Facility at the Alternative Base Rate ("ABR"), which is 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 under the Credit Facility for the three and nine months ended September 30, 2014 was 1.92% and 2.08%, respectively, exclusive of commitment fees. For the three and nine months ended September 30, 2014, interest expense was $0.4 million and $1.4 million, respectively, and commitment fees were $0.7 million and $2.0 million, respectively, under the Credit Facility. 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, 2014, the Company's current ratio was 2.6 and leverage ratio was 2.8. In addition, the Company is subject to covenants limiting dividends and other restricted payments, transactions with affiliates, incurrence of debt, changes of control, asset sales and liens on properties.

9.500% Senior Notes due 2018. In accordance with the provisions of the indenture governing the Company's 9.500% Senior Notes, on May 5, 2014, the Company redeemed all of the outstanding notes in full at a price of 104.75% of the principal amount, plus accrued and unpaid interest. The Company paid an aggregate amount of $210.6 million for such redemption, consisting of a call premium of $9.5 million and $1.1 million of accrued and unpaid interest. The call premium of $9.5 million and remaining unamortized debt issuance costs of $3.1 million were included in Other expense in the Company's Consolidated Statement of Operations for the nine months ended September 30, 2014.

5.625% Senior Notes due 2021. 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 (the "5.625% Senior Notes"). 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 (the "Base Indenture"), as supplemented by a first supplemental indenture (as so supplemented, the "5.625% Senior Notes Indenture") with Wells Fargo Bank, National Association, as trustee. Provisions of the 5.625% 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 5.625% Senior Notes Indenture also contains customary events of default.

5.875% Senior Notes due 2022. On November 15, 2013, the Company completed its public offering of $600.0 million in aggregate principal amount of 5.875% Senior Notes due 2022 (the "5.875% Senior Notes due 2022"). Interest is payable on the 5.875% Senior Notes due 2022 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2022 were issued under the Base Indenture, as supplemented by a second supplemental indenture with Wells

Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 5.625% Senior Notes Indenture.

5.875% Senior Notes due 2024. On May 29, 2014, the Company completed its public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024 (the “5.875% Senior Notes due 2024” and, together with the 5.625% Senior Notes and the 5.875% Senior Notes due 2022, the “Senior Notes”). Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1. The 5.875% Senior Notes due 2024 were issued under the Base Indenture, as supplemented by a third supplemental indenture with Wells Fargo Bank, National Association, as trustee, which contains covenants and events of default substantially similar to those in the 5.625% Senior Notes Indenture.

Total Indebtedness. As of September 30, 2014, the Company had total outstanding borrowings of $1.91 billion, and for the nine months ended September 30, 2014, the Company’s weighted average borrowing rate was 5.93%, inclusive of interest and commitment fees.

(8) Income Taxes

The Company's effective tax rate for the three and nine months ended September 30, 2014 was 36.5% and 36.2%, respectively, and the effective tax rate for the three and nine months ended September 30, 2013 was 36.7% and 35.5%, respectively. The provision for income taxes for the three and nine months ended September 30, 2014 differs from the tax computed at the federal statutory income tax rate primarily due to the impact of state income taxes and the non-deductibility of certain incentive compensation. As of September 30, 2014 and December 31, 2013, 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, 2014, the Company had a net deferred tax liability of $178.3 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.

(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 4.9 MMBbls of oil by the end of 2017 and 601 million MMBtus of natural gas by mid-year 2028. 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. As the Company develops additional reserves in the Eagle Ford area, it anticipates exceeding its current minimum volume commitments and therefore intends to enter into additional transportation and processing commitments in the future. These future transportation and processing commitments could expose the Company to additional volume deficiency payments. As of September 30, 2014, the Company has accrued deficiency fees of $6.5 million and expects to continue to accrue deficiency fees under its commitments. Future obligations under firm oil and natural gas transportation and processing agreements as of September 30, 2014 are as follows:

	September 30, 2014 (In thousands)
2014	$ 5,575
2015	22,120
2016	22,132
2017	21,708
2018	18,159
Thereafter	102,406
Total future obligations	$ 192,100

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. As of September 30, 2014, the Company had four outstanding drilling rig commitments with terms greater than one year that will expire by the end of 2016, and the minimum contractual commitments due in the next twelve months were $25.9 million. Payments under these commitments are accounted for as capital additions to oil and gas properties. As of September 30, 2014, the Company’s minimum contractual commitments due in the next twelve months for completion services agreements for the stimulation, cementing and delivery of drilling fluids and other field service commitments were $9.0 million. Payments under these commitments are accounted for as capital additions to oil and gas properties or as Lease operating expense, depending on the nature of the related expenditures.

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

Commercial Disputes. The Company recorded a reserve of $5.8 million related to a dispute that arose during the third quarter of 2014. The Company continues to work to settle the dispute, however no certainty exists that a settlement will be reached or, if so, the amount of such settlement. Therefore, the ultimate loss could be greater or less than the amount accrued. The reserve for this contingency is reported in Reserve for commercial disputes in the Consolidated Statement of Operations for the three and nine months ended September 30, 2014.

(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 EPS 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,	
	2014	2013	2014	2013
	(In thousands)			
Basic weighted average number of shares outstanding	61,484	61,152	61,439	57,656
Dilution effect of stock option and restricted shares at the end of the period	191	212	197	268
Diluted weighted average number of shares outstanding	61,675	61,364	61,636	57,924
Anti-dilutive stock awards and shares	5	—	3	—

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 for net proceeds of approximately $286.3 million ($40.80 per share, net of underwriting discounts and commissions), including offering expenses and reimbursements by the underwriters of certain expenses incurred in connection with the offering. The Company also received net proceeds of approximately $43.0 million in connection with the underwriters' full exercise of their over-allotment option to purchase 1,050,000 additional shares of common stock, which closed on April 29, 2013.

(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,	
	2014	2013	2014	2013
	(In thousands)			
Total stock-based compensation expense	$2,640	$3,621	$10,280	$8,662
Capitalized in oil and gas properties	(212)	(221)	(459)	(369)
Net stock-based compensation expense	$2,428	$3,400	$9,821	$8,293

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, 2014, the Company recorded compensation expense of approximately $2.7 million and $7.8 million, respectively, related to these equity awards. As of September 30, 2014, unrecognized stock-based compensation expense related to unvested restricted stock was approximately $14.7 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, 2014, the Company recognized compensation expense of ($0.1) million and $2.5 million, respectively, associated with the PSUs. At the current fair value as of September 30, 2014, 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 $15.5 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 2014 annual meeting under the heading "Compensation Discussion and Analysis" and the Company's 2013 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. 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, 2014, this expense was immaterial.

(12) Guarantor Subsidiaries

The Company’s Senior Notes are guaranteed by its wholly owned subsidiaries. Rosetta Resources Inc., as the parent company, has no independent assets or operations. The guarantees are full and unconditional and joint and several. 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,” “plan,” “project,” “intend,” “anticipate,” “believe,” “estimate,” “forecast,” “predict,” “potential,” “pursue,” “target” or “continue,” the such terms or variations thereon, or other comparable terminology. Unless the context clearly indicates otherwise, references in this report to “Rosetta,” “the Company,” “we,” “our,” “us” or like terms refer to Rosetta Resources Inc. and its subsidiaries.

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, 2013 (the “2013 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;
- 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 expenses;
- failure of joint interest partners to pay us our share of revenue;
- the occurrence of property acquisitions or divestitures;
- reserve levels;
- inflation or deflation;
- 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, completion, production and facility risks;

- 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;
- electronic, cyber or physical security breaches; and
- any other factors that impact or could impact the exploration and development of oil, NGLs 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, NGLs and natural gas.

Overview

The following discussion addresses material changes in our results of operations for the three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013 and material changes in our financial condition since December 31, 2013. This discussion should be read in conjunction with our 2013 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, 2014 include the following:

- production of 73.5 MBoe/d compared to 50.9 MBoe/d for the three months ended September 30, 2013;
- 36 gross (35.7 net) operated wells drilled compared to 43 gross (42.5 net) operated wells drilled for the three months ended September 30, 2013; and
- net income of $78.4 million, or $1.27 per diluted share, compared to $41.0 million, or $0.67 per diluted share, for the three months ended September 30, 2013.

Results for the nine months ended September 30, 2014 include the following:

- production of 63.2 MBoe/d compared to 48.9 MBoe/d for the nine months ended September 30, 2013;
- 117 gross (114.9 net) operated wells drilled compared to 97 gross (96.5 net) operated wells drilled for the nine months ended September 30, 2013; and
- net income of $128.1 million, or $2.08 per diluted share, compared to $169.9 million, or $2.93 per diluted share, for the nine months ended September 30, 2013.

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 United States.

Rosetta is a significant producer in the liquids-rich window of the Eagle Ford region and we have established an inventory of high-return drilling opportunities that offer predictable and long-term production, reserve growth and a more valuable commodity mix. Our Permian Basin assets and bolt-on activity further expand our portfolio of long-lived, oil-rich resource projects that will drive our long-term growth and sustainability. During the first quarter of 2014, we acquired additional Delaware Basin assets from several private parties for total cash consideration of $83.8 million. The acquisition covered 5,034 net acres located in Reeves County. The acquired assets included 13 gross producing wells (11 operated) and added future horizontal drilling locations to expand our capital project inventory. We will continue to consider investments in the Eagle Ford shale region and in the Permian Basin that offer a viable inventory of projects, including resource-based exploration projects, producing property acquisitions in early development stages and acreage swaps.

Our development operations in the Eagle Ford shale are primarily focused in several 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 Briscoe Ranch lease in Dimmit County, and have three leases located in the Central Dimmit County area and the Tom Hanks lease in northern LaSalle County, where our positions were delineated in 2011, 2012 and 2013, respectively. In addition, we are evaluating several operated pilot wells testing the Upper Eagle Ford. Overall, we hold 60,000 net acres in the region with approximately 47,000 acres located in the liquids-producing portions of the play. Our operations in the Permian are focused in Reeves County in the Delaware Basin where we are testing multiple benches in the Wolfcamp and 3rd Bone Spring. Currently, we hold 47,000 net acres in the Delaware Basin and approximately 13,000 net exploratory acres in the Midland Basin.

The ongoing development of our assets in South Texas, which averaged approximately 65.2 MBoe/d for the three months ended September 30, 2014, an increase of 15 percent from the second quarter of 2014, has contributed to record liquids volumes for the Company. Production from the Permian averaged approximately 8.2 MBoe/d in the third quarter of 2014, an increase of 82 percent from the second quarter of 2014, reflecting our successful delineation activity and adding to our crude oil mix. For the three months ended September 30, 2014, our commodity mix was 29 percent crude oil, 35 percent NGLs and 36 percent natural gas. The Eagle Ford area accounted for approximately 89 percent of our total production for the three months ended September 30, 2014. In addition, crude oil and NGLs represented approximately 61 percent of our production from the Eagle Ford area and 87 percent of our production from the Permian.

We drilled 36 gross operated wells and completed 32 gross operated wells during the quarter ended September 30, 2014. Of these totals, 24 wells were drilled and 23 completed in the Eagle Ford area. In the Delaware Basin, we drilled 12 gross operated wells, including nine horizontal and three vertical wells. A total of nine gross operated wells were successfully completed, seven of which were horizontal wells. As of September 30, 2014, we had completed a total of 295 gross wells in the Eagle Ford shale since entering the play in 2009. Since initiating our Permian operations in August 2013, we have completed 16 horizontal wells.

In the third quarter of 2014, total daily equivalent production reached an all-time high of 73.5 MBoe/d, an increase of 44 percent from the same period in 2013 and 20 percent from the prior quarter. For the same period, total daily crude oil production was 21.2 MBbls/d, an increase of 39 percent from the same period in 2013, and 12 percent from the prior quarter. To handle our increased production, we have multiple options for transportation and processing capacity with firm commitments and other arrangements in place to meet total planned production levels through 2015. We will continue to evaluate adding more firm capacity in our operating areas.

Our 2014 capital program is expected to total $1.2 billion, excluding capital used to fund the 2014 Permian Acquisition. The 2014 program is based on an average of four to five-rig Eagle Ford program and a five to six-rig Permian program, including four rigs dedicated to horizontal drilling. Approximately $785 million, or 65 percent of our 2014 capital program, will be spent on development activities in the Eagle Ford shale in South Texas, including about $120 million allocated to central facilities projects for our planned 2014 and 2015 well programs. Approximately $330 million, or 28 percent, will be spent on activities in the Delaware Basin in West Texas. In addition, the 2014 budget allocates approximately $85 million for other capital items, including evaluation of new venture opportunities, capitalized interest and other corporate capital.

While our unconventional resource strategy has proven to be successful, we recognize 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 a diversified production base which includes a balanced mix of crude oil, NGLs and natural gas. Because our production is highly concentrated geographically, we have taken various steps to provide access to necessary services and infrastructure. We believe our 2014 capital program can be executed from internally generated cash flows, borrowings under our Credit Facility, access to capital markets and cash on hand. 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. On September 30, 2014, our semi-annual borrowing base redetermination was completed and our borrowing base and committed amounts under the Credit Facility were reconfirmed by our lenders at $950 million and $800 million, respectively. As of September 30, 2014, we had $110 million of borrowings outstanding with $690 million available for borrowing under the Credit Facility.

On May 5, 2014, we redeemed our 9.500% Senior Notes with borrowings under the Credit Facility for a total payment of $210.6 million, which includes the principal amount, a call premium and accrued and unpaid interest. On May 29, 2014, we completed our public offering of $500.0 million in aggregate principal amount of 5.875% Senior Notes due 2024. Interest is payable on the 5.875% Senior Notes due 2024 semi-annually on June 1 and December 1.

Results of Operations

Revenues

Our consolidated financial statements for the three months ended September 30, 2014 reflect total revenues of $365.6 million (including derivative gains of $77.2 million) based on total volumes of 73.5 MBoe/d. Our consolidated financial statements for the nine months ended September 30, 2014 reflect total revenues of $801.0 million (including derivative gains of $4.0 million) based on total volumes of 63.2 MBoe/d.

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,		
	2014	2013	% Change Increase/ (Decrease)	2014	2013	% Change Increase/ (Decrease)
Revenues (in thousands):						
Oil sales	$168,016	$140,172	20 %	$462,396	$353,119	31 %
NGL sales	66,003	50,857	30 %	176,740	144,236	23 %
Natural gas sales	54,359	34,136	59 %	157,878	108,369	46 %
Derivative instruments	77,215	(30,597)	352 %	4,035	3,484	16 %
Total revenues	$365,593	$194,568	88 %	$801,049	$609,208	31 %
Production:						
Oil (MBbls)	1,948	1,396	40 %	5,133	3,622	42 %
NGLs (MBbls)	2,389	1,650	45 %	5,990	4,794	25 %
Natural gas (MMcf)	14,552	9,843	48 %	36,717	29,663	24 %
Total equivalents (MBoe)	6,763	4,686	44 %	17,243	13,360	29 %
Daily Production:						
Oil (MBbls/d)	21.2	15.2	39 %	18.8	13.3	41 %
NGLs (MBbls/d)	26.0	17.9	45 %	21.9	17.6	24 %
Natural gas (MMcf/d)	158.2	107.0	48 %	134.5	108.7	24 %
Total equivalents (MBoe/d)	73.5	50.9	44 %	63.2	48.9	29 %
Average sales price:						
Oil, excluding derivatives (per Bbl)	$86.25	$100.41	(14 %)	$90.08	$97.49	(8 %)
Oil, including realized derivatives (per Bbl)	85.09	98.14	(13 %)	88.02	95.72	(8 %)
NGL, excluding derivatives (per Bbl)	27.63	30.82	(10 %)	29.51	30.09	(2 %)

NGL, including realized derivatives (per Bbl)	28.72	32.60	(12	%)	29.62	32.19	(8	%)
Natural gas, excluding derivatives (per Mcf)	3.74	3.47	8	%	4.30	3.65	18	%
Natural gas, including realized derivatives (per Mcf)	3.74	3.64	3	%	4.21	3.76	12	%
Revenue, excluding derivatives (per Boe)	42.64	48.05	(11	%)	46.22	45.34	2	%
Revenue, including realized derivatives (per Boe)	42.71	48.36	(12	%)	45.46	45.84	(1	%)

Oil sales. For the three and nine months ended September 30, 2014, oil sales, excluding the effect of derivative instruments, increased by $27.8 million and $109.3 million, respectively, from the same periods in 2013. For the three months ended September 30, 2014, the 6.0 MBbls/d increase in oil production resulted in a $55.5 million increase in oil sales, which was partially offset by a $27.6 million decrease due to a lower average sales price for oil. The increase in oil production was primarily attributable to a 4.2 MBbls/d increase resulting from our growth and development in the Permian Basin and a 2.0 MBbls/d increase resulting from our continued development in the Tom Hanks lease. For the nine months ended September 30, 2014, the 5.5 MBbls/d increase in oil production resulted in a $147.3 million increase in oil sales, which was partially offset by a $38.0 million decrease due to a lower average sales price for oil. The increase in oil production was primarily attributable to a 3.3 MBbls/d increase resulting from our entry into the Permian Basin and a 2.0 MBbls/d increase resulting from our continued development in the Tom Hanks lease.

Oil derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2014, realized oil derivative losses were $2.2 million and $10.6 million, respectively, compared to realized oil derivative losses of $3.1 million and $6.4 million for the three and nine months ended September 30, 2013, respectively.

NGL sales. For the three and nine months ended September 30, 2014, NGL sales, excluding the effect of derivative instruments, increased by $15.1 million and $32.5 million, respectively, from the same periods in 2013. For the three months ended September 30, 2014, the 8.1 MBbls/d increase in NGL production resulted in a $22.8 million increase in NGL sales, which was partially offset by a $7.7 million decrease due to a lower average sales price for NGLs. The increase in NGL production was primarily attributable to an increase of 4.9 MBbls/d at Gates Ranch and an increase of 2.7 MBbls/d from the Briscoe Ranch area as a result of our continued development activities in those areas. For the nine months ended September 30, 2014, the 4.3 MBbls/d increase in NGL production resulted in a $36.0 million increase in NGL sales, which was partially offset by a $3.5 million decrease due to a lower average sales price for NGLs. The increase in NGL production was primarily attributable to an increase of 2.4 MBbls/d from the Briscoe Ranch area and a 1.6 MBbls/d increase at Gates Ranch.

NGL derivative gains and losses are reported as a component of Derivative instruments within Revenues. For the three and nine months ended September 30, 2014, we realized NGL derivative gains of $2.6 million and $0.7 million, respectively, compared to realized NGL derivative gains of $2.9 million and $10.1 million for the three and nine months ended September 30, 2013, respectively.

Natural gas sales. For the three and nine months ended September 30, 2014, natural gas sales, excluding the effect of derivative instruments, increased by $20.2 million and $49.5 million, respectively, from the same periods in 2013. For the three months ended September 30, 2014, the 51.2 MMcf/d increase in natural gas production resulted in a $16.3 million increase in natural gas sales, and an increase in the average sales price for natural gas increased natural gas sales by $3.9 million. The increase in natural gas production was primarily attributable to an increase of 27.8 MMcf/d at Gates Ranch in addition to development activities at Briscoe Ranch and the Encinal area, where natural gas production increased by 13.7 MMcf/d and 7.6 MMcf/d, respectively. For the nine months ended September 30, 2014, the 25.8 MMcf/d increase in natural gas production resulted in a $25.8 million increase in natural gas sales, and an increase in the average sales price for natural gas increased natural gas sales by $23.7 million. The increase in natural gas production was primarily attributable to development activities at Briscoe Ranch and the Encinal area, where natural gas production increased by 12.9 MMcf/d and 5.1 MMcf/d, respectively, in addition to an increase at Gates Ranch of 6.0 MMcf/d.

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, 2014, we realized a natural gas derivative gain of $0.1 million and a loss of $3.3 million, respectively, compared to realized natural gas derivative gains of $1.7 million and $3.1 million for the three and nine months ended September 30, 2013, respectively.

Derivative instruments. For the three and nine months ended September 30, 2014, Derivative instruments included (i) a realized derivative gain of $0.5 million and a loss of $13.2 million, respectively, from cash settlements associated with our commodity derivative contracts, and (ii) unrealized derivative gains of $76.7 million and $17.2 million, respectively, due to changes in the fair value of our commodity derivative contracts.

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

Operating Expenses

The following table summarizes our production costs and operating expenses for the periods indicated:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2014	2013	% Change Increase/ (Decrease)	2014	2013	% Change Increase/ (Decrease)
	(In thousands, except percentages and per unit amounts)			(In thousands, except percentages and per unit amounts)		
Direct lease operating expense	$19,901	$13,309	50 %	$50,455	$32,718	54 %
Insurance expense	293	404	(27 %)	874	761	15 %
Workover expense	6,758	2,141	216 %	20,208	2,503	707 %
Lease operating expense (Production costs)	$26,952	$15,854	70 %	$71,537	$35,982	99 %
Treating and transportation	23,638	18,807	26 %	62,933	52,414	20 %
Taxes, other than income	13,191	7,896	67 %	35,656	24,286	47 %
Depreciation, depletion and amortization (DD&A)	128,255	60,915	111 %	293,670	153,382	91 %
Reserve for commercial disputes	5,800	-	100 %	5,800	-	100 %
General and administrative costs	23,438	18,790	25 %	64,643	52,830	22 %
Costs and expenses (per Boe of production)						
Lease operating expense (Production costs)	$3.99	$3.38	18 %	$4.15	$2.69	54 %
Treating and transportation	3.50	4.01	(13 %)	3.65	3.92	(7 %)
Taxes, other than income	1.95	1.69	15 %	2.07	1.82	14 %
Depreciation, depletion and amortization (DD&A)	18.96	13.00	46 %	17.03	11.48	48 %
General and administrative costs	3.47	4.01	(14 %)	3.75	3.95	(5 %)
General and administrative costs, excluding stock-based compensation	3.11	3.28	(5 %)	3.18	3.33	(5 %)

Lease operating expense. Lease operating expense increased $11.1 million and $35.6 million for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended September 30, 2014 was the result of increased Eagle Ford operations, which contributed $8.5 million of the increase, including $4.5 million of incremental well workover costs, and increased Permian activity, which represented $3.4 million of the increase. The increase for the nine months ended September 30, 2014 was the result of increased Eagle Ford operations, which contributed $24.4 million of the increase, including $12.9 million of incremental well workover costs, and the 2013 Permian Acquisition, which represented $14.2 million of the increase. These increases were partially offset by a decline in costs of $3.0 million primarily due to the suspension of drilling programs in non-core areas.

Treating and transportation. Treating and transportation expense increased $4.8 million and $10.5 million for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013. While daily production increased in both core areas, per unit expense for the three and nine months ended September 30, 2014 decreased primarily due to the utilization of lower-cost transportation and processing primarily in the Eagle Ford area.

Additionally, we have accrued deficiency fees of $2.4 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, 2014, respectively.

Taxes, other than income. Taxes, other than income include production taxes and ad valorem taxes. Production taxes are based on revenues generated from production, and ad valorem taxes are based on the valuation of the underlying assets. Taxes, other than income increased $5.3 million and $11.4 million for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended September 30, 2014 was the result of a 22.6 MBoe/d increase in production, which represented $3.5 million of the increase, and a $0.26 per Boe increase in unit costs, which represented $1.8 million of the increase. These higher unit costs resulted from increased oil production, which generally qualifies for fewer production tax incentives, as well as from a reduction in the high-cost gas tax exemption that our gas-directed wells have historically received. The increase for the nine months ended September 30, 2014 was the result of a 14.3 MBoe/d increase in production, which represented $7.1 million of the increase, and a $0.25 per Boe increase in unit costs, which represented $4.3 million of the increase.

Depreciation, depletion and amortization. DD&A expense increased $67.3 million and $140.3 million for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013. The increases were a result of increased depletion rates due to the inclusion of higher-cost Permian reserves in our depletion pool, as well as increased daily production of 44% and 29%, respectively.

Reserve for commercial disputes. We recorded a reserve of $5.8 million related to a dispute that arose during the third quarter of 2014. We continue to work to settle the dispute, however no certainty exists that a settlement will be reached or, if so, the amount of such settlement. Therefore, the ultimate loss could be greater or less than the amount accrued. The reserve for this contingency is reported in Reserve for commercial disputes in the Consolidated Statement of Operations for the three and nine months ended September 30, 2014.

General and administrative costs. General and administrative costs increased $4.6 million and $11.8 million for the three and nine months ended September 30, 2014, respectively, as compared to the same periods in 2013. The increase for the three months ended September 30, 2014 was primarily due to a $4.2 million increase in personnel costs attributable to increased headcount. The increase for the nine months ended September 30, 2014 was primarily due to an $11.8 million increase in personnel costs attributable to increased headcount.

Total Other Expense

Total other expense, which includes Interest expense, net of interest capitalized; Interest income; and Other expense, increased $13.4 million and $39.1 million for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. The increase for the three months ended September 30, 2014 was a result of 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, 2014 was primarily due to a $9.5 million call premium and the write-off of $3.1 million of remaining unamortized debt issuance costs associated with the redemption of our 9.500% Senior Notes, an increase in debt outstanding compared to the prior comparable period, partially offset by higher capitalized interest. The weighted average interest rates, inclusive of interest and commitment fees, for the three and nine months ended September 30, 2014 were 5.74% and 5.93%, respectively, compared to 5.77% and 5.95%, respectively, for the same periods in 2013.

Provision for Income Taxes

The effective tax rate for the three and nine months ended September 30, 2014 was 36.5% and 36.2%, respectively, and the effective tax rate for the three and nine months ended September 30, 2013 was 36.7% and 35.5%, respectively. The provision for income taxes 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. As of September 30, 2014 and December 31, 2013, 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, 2014, we had a net deferred tax liability of $178.3 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, our Credit Facility and our cash on hand, which can be accessed as needed to supplement operating cash flow.

Operating Cash Flow. Our cash flows depend on many factors, including the price of oil, NGLs and natural gas and the success of our development and exploration activities. 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,	
	2014	2013
	(In thousands)	
Cash provided by (used in):		
Operating activities	$510,791	$469,423
Investing activities	(1,080,408)	(1,522,245)
Financing activities	399,460	1,079,992
Net (decrease) increase in cash and cash equivalents	$(170,157)	$27,170

Operating Activities. The increase in net cash provided by operating activities for the nine months ended September 30, 2014 compared to the same period in 2013 reflects increased production and more favorable natural gas prices.

Investing Activities. The reduction in net cash used in investing activities for the nine months ended September 30, 2014 compared to the same period in 2013 reflects a reduction in our acquisition activity, partially offset by higher capital spending related to our Eagle Ford drilling program and further development in the Permian Basin.

Financing Activities. The reduction in net cash provided by financing activities for the nine months ended September 30, 2014 compared to the same period in 2013 reflects a reduction in debt and equity issuances, along with the redemption of our 9.500% Senior Notes in 2014.

Capital Expenditures and Requirements

Our historical capital expenditures summary table is included in Items 1 and 2. Business and Properties in our 2013 Annual Report and is incorporated herein by reference.

Excluding acquisitions, our accrual-basis capital expenditures for the nine months ended September 30, 2014 increased by $423.0 million to $1.029 billion from $606.0 million for the nine months ended September 30, 2013. During the nine months ended September 30, 2014, we drilled 117 and completed 123 gross wells, the majority of which are located in the Eagle Ford area. Excluding capital used to fund the 2014 Permian Acquisition, our capital budget for 2014 is projected to be $1.2 billion.

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.

Commodity Price Risk and Related Derivative Activities

The energy markets have historically been very volatile and oil, NGL and natural gas prices may 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 and costless collars. Although not risk-free, we believe these activities will reduce our exposure to commodity price fluctuations and thereby enable us to achieve a more predictable cash flow. Consistent with this policy, we have entered into a series of oil, NGL and natural gas fixed price swaps and costless collars for each year through 2016. Our fixed price 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 anticipated production 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, 2014, a description of the applicable accounting and the estimated fair market values as of September 30, 2014. 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 2013 Annual Report.

Critical Accounting Policies and Estimates

Management makes many estimates and assumptions in the application of GAAP 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 2013 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 we develop additional 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 in the Eagle Ford area could expose us to additional volume deficiency payments and as of September 30, 2014, we have accrued deficiency fees of $6.5 million. As of September 30, 2014, we had no such commitments in the Permian area, but as these assets are developed and additional firm capacity for the transportation and processing of our production is added, we could be subject to periodic deficiency payments.

We are party to various legal and regulatory proceedings and commercial disputes arising in the normal course of business. The ultimate outcome of each of these matters cannot be absolutely determined, and in the event of a negative outcome as to any proceeding, the liability we may ultimately incur with respect to such proceeding may be in excess of amounts currently accrued, if any. After considering our available insurance and, to the extent applicable, that of third parties, and the performance of contractual defense and indemnity rights and obligations, where applicable, we do not believe any such matters will have 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 recorded a reserve of $5.8 million related to a commercial dispute.

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 2013 Annual Report and Note 4 – Commodity Derivative Contracts included in Part I. Item 1. Financial Statements of this Form 10-Q.

As of September 30, 2014, we had open crude oil derivative contracts in a net asset position with a fair value of $12.2 million. A 10% increase in crude oil prices would reduce the fair value by approximately $62.9 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $63.5 million. The effects of these derivative transactions on our revenues are discussed above under Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Revenues.

As of September 30, 2014, we had open NGL derivative contracts in a net asset position with a fair value of $4.9 million. A 10% increase in NGL prices would reduce the fair value by approximately $11.0 million, while a 10% decrease in NGL prices would increase the fair value by approximately $11.0 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, 2014, we had open natural gas derivative contracts in a net asset position with a fair value of $4.6 million. A 10% increase in natural gas prices would reduce the fair value by approximately $18.6 million, while a 10% decrease in natural gas prices would increase the fair value by approximately $19.2 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.

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

As of September 30, 2014, our derivative instruments are with counterparties who are lenders under our 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, 2014, we had no deposits for collateral regarding commodity derivative positions. 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, 2014. Our third-party provider evaluated nonperformance 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, 2014. We are not aware of any circumstances which currently exist 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 anticipated production through 2016. These derivative contracts may limit our potential revenue if oil, NGL and natural gas prices exceed the prices established by the contracts. As of September 30, 2014, 65% of our crude oil derivative transactions represented hedged prices of crude oil at West Texas Intermediate on the NYMEX with the remaining 35% at Light Louisiana Sweet; 100% of our total NGL derivative transactions represented hedged prices of NGLs at Mont Belvieu; and 80% of our natural gas derivative transactions represented hedged prices of natural gas at Houston Ship Channel, and 20% at Tennessee, zone 0.

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, 2014. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2014, 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, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. Other Information

Item 1. Legal Proceedings

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 2013 Annual Report and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2014.

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, 2014:

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	967	$ 54.73	—	—
August 1 - August 31	1,450	50.11	—	—
September 1 - September 30	925	47.97	—	—
Total	3,342	$ 50.85	—	—

(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.

Item 6. Exhibits

Exhibit Number	Description
4.1	Third Supplemental Indenture, dated as of May 29, 2014, 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 to the Company's Current Report on Form 8-K filed on May 29, 2014 (Registration No. 000-51801)).
31.1*	Certification of Periodic Financial Reports by Chief Executive Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Periodic Financial Reports by Chief Financial Officer in satisfaction of Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Periodic Financial Reports by Chief Executive Officer and Chief Financial Officer in satisfaction of Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

*Filed herewith

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 3, 2014

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