UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2014

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 1-35372

Sanchez Energy Corporation
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3090102** (I.R.S. Employer Identification No.)
1111 Bagby Street, Suite 1800 **Houston, Texas** (Address of principal executive offices)	**77002** (Zip Code)

(713) 783-8000
(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 ☒ 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 ☒ 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 the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ 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 Exchange Act). Yes ☐ No ☒

Number of shares of registrant's common stock, par value $0.01 per share, outstanding as of August 8, 2014: 58,394,498.

We were previously considered an “emerging growth company” as defined under the Jumpstart Our Business Startups Act of 2012, commonly referred to as the “JOBS Act.” The JOBS Act permits a company to be classified as an “emerging growth company” for up to five years from the date of the completion of its initial public offering or until the earlier of (1) the last day of the fiscal year in which its total annual gross revenues exceed $1 billion, (2) the date that it becomes a “large accelerated filer” as defined in Rule 12b-2 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), which would occur if the market value of its common equity that is held by non- affiliates is $700 million or more as of the last business day of its most recently completed second fiscal quarter or (3) the date on which it has issued more than $1 billion in non-convertible debt during the preceding three year period. However, during the second quarter of 2014, the Company issued non-convertible debt such that we have now issued more than $1 billion in non-convertible debt during the preceding three year period. As such, we are no longer considered an “emerging growth company” under the JOBS Act.

Further, as of June 30, 2014, the market value of our common equity held by non-affiliates was greater than $700 million. As such, the Company will become a large accelerated filer as defined in Rule 12b-2 under the Exchange Act at December 31, 2014.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains “forward-looking statements” within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, included in this Quarterly Report on Form 10-Q that address activities, events or developments that we expect, believe or anticipate will or may occur in the future are forward-looking statements. These statements are based on certain assumptions we made based on management’s experience, perception of historical trends and technical analyses, current conditions, anticipated future developments and other factors believed to be appropriate and reasonable by management. When used in this Quarterly Report on Form 10- Q, words such as “will,” “potential,” “believe,” “estimate,” “intend,” “expect,” “may,” “should,” “anticipate,” “could,” “plan,” “predict,” “project,” “profile,” “model,” “strategy,” “future” or their negatives or the statements that include these words or other words that convey the uncertainty of future events or outcomes, are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, statements, express or implied, concerning our future operating results and returns or our ability to replace or increase reserves, increase production, or generate income or cash flows are forward-looking statements. Forward-looking statements are not guarantees of performance. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond our control. Although we believe that the expectations reflected in our forward-looking statements are reasonable and are based on reasonable assumptions, no assurance can be given that these assumptions are accurate or that any of these expectations will be achieved (in full or at all) or will prove to have been correct. Important factors that could cause our actual results to differ materially from the expectations reflected in the forward-looking statements include, among others:

- our ability to successfully execute our business and financial strategies;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- the realized benefits of the acreage acquired in our various acquisitions and other assets and liabilities assumed in connection therewith;
- the extent to which our drilling plans are successful in economically developing our acreage in, and to produce reserves and achieve anticipated production levels from, our existing and future projects;

- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may therefore be imprecise;
- the extent to which we can optimize reserve recovery and economically develop our plays utilizing horizontal and vertical drilling, advanced completion technologies and hydraulic fracturing;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;
- competition in the oil and natural gas exploration and production industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- the timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids ("NGLs"), natural gas and related commodities;
- our ability to compete with other companies in the oil and natural gas industry;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
- developments in oil-producing and natural gas-producing countries;
- our ability to effectively integrate acquired crude oil and natural gas properties into our operations, fully identify existing and potential problems with respect to such properties and accurately estimate reserves, production and costs with respect to such properties;
- the extent to which our crude oil and natural gas properties operated by others are operated successfully and economically;
- the use of competing energy sources and the development of alternative energy sources;
- unexpected results of litigation filed against us;
- the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage; and
- the other factors described under "Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations," "Part II, Item 1A. Risk Factors" and elsewhere in this Quarterly Report on Form 10-Q and in our other public filings with the Securities and Exchange Commission (the "SEC").

In light of these risks, uncertainties and assumptions, the events anticipated by our forward-looking statements may not occur, and, if any of such events do, we may not have correctly anticipated the timing of their occurrence or the extent of their impact on our actual results. Accordingly, you should not place any undue reliance on any of our forward-looking statements. Any forward- looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Sanchez Energy Corporation
Form 10-Q
For the Quarterly Period Ended June 30, 2014

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PART I—FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

Sanchez Energy Corporation

Condensed Consolidated Balance Sheets (Unaudited)

(in thousands, except share amounts)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$ 385,871	$ 153,531
Oil and natural gas receivables	56,456	51,960
Joint interest billing receivables	15,470	5,803
Fair value of derivative instruments	64	—
Deferred tax asset	18,471	6,882
Other current assets	5,893	1,386
Total current assets	482,225	219,562
Oil and natural gas properties, at cost, using the full cost method:		
Unproved oil and natural gas properties	400,060	244,570
Proved oil and natural gas properties	2,051,312	1,297,961
Total oil and natural gas properties	2,451,372	1,542,531
Less: Accumulated depreciation, depletion, amortization and impairment	(288,258)	(157,043)
Total oil and natural gas properties, net	2,163,114	1,385,488
Other assets:		
Debt issuance costs, net	45,157	19,806
Fair value of derivative instruments	108	1,304
Other assets	13,450	2,993
Total assets	$2,704,054	$1,629,153
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 11,663	$ 46,900
Accounts payable—related entities	1,888	961
Other payables	6,907	2,963
Accrued liabilities	123,552	102,455
Deferred premium liability	3,143	717
Fair value of derivative instruments	27,148	4,623
Total current liabilities	174,301	158,619
Long term debt, net of discount	1,443,710	593,258
Asset retirement obligations	22,626	4,130
Deferred tax liability	17,778	10,868
Deferred premium liability	2,465	4,891
Fair value of derivative instruments	9,421	78
Total liabilities	1,670,301	771,844
Commitments and contingencies (Note 15)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 15,000,000 shares authorized; 1,886,485 and 3,000,000 shares issued and outstanding as of June 30, 2014 and December 31, 2013 of 4.875% Convertible Perpetual Preferred Stock, Series A, respectively; 3,532,330 and 4,500,000 shares issued and outstanding as of June 30, 2014 and December 31, 2013 of 6.500% Convertible Perpetual Preferred Stock, Series B, respectively)	54	75
Common stock ($0.01 par value, 150,000,000 shares authorized; 58,125,398 and 46,368,713 shares issued and outstanding as of June 30, 2014 and December 31, 2013, respectively)	581	464
Additional paid-in capital	1,077,494	867,108
Accumulated deficit	(44,376)	(10,338)
Total stockholders' equity	1,033,753	857,309
Total liabilities and stockholders' equity	$2,704,054	$1,629,153

The accompanying notes are an integral part of these condensed consolidated financial statements.

Sanchez Energy Corporation

Condensed Consolidated Statements of Operations (Unaudited)

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
REVENUES:				
Oil sales	$136,902	$54,872	$256,577	$84,199
Natural gas liquids sales	8,116	2,047	16,609	2,976
Natural gas sales	6,643	2,166	13,037	2,946
Total revenues	151,661	59,085	286,223	90,121
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	13,911	6,813	29,823	10,072
Production and ad valorem taxes	7,842	3,361	18,245	5,411
Depreciation, depletion, amortization and accretion	70,583	24,623	131,834	37,996
General and administrative (inclusive of stock-based compensation expense of $15,943 and $4,578, respectively, for the three months ended June 30, 2014 and 2013, and $25,878 and $7,712, respectively, for the six months ended June 30, 2014 and 2013)	28,869	12,632	48,178	20,369
Total operating costs and expenses	121,205	47,429	228,080	73,848
Operating income	30,456	11,656	58,143	16,273
Other income (expense):				
Interest and other income	3	51	15	72
Interest expense	(17,261)	(7,069)	(30,533)	(8,153)
Net gains (losses) on commodity derivatives	(31,900)	4,252	(41,017)	624
Total other expense, net	(49,158)	(2,766)	(71,535)	(7,457)
Income (loss) before income taxes	(18,702)	8,890	(13,392)	8,816
Income tax benefit	(6,544)	—	(4,679)	—
Net income (loss)	(12,158)	8,890	(8,713)	8,816
Less:				
Preferred stock dividends	(7,132)	(5,484)	(25,325)	(7,556)
Net income allocable to participating securities	—	(159)	—	(56)
Net income (loss) attributable to common stockholders	$ (19,290)	$ 3,247	$ (34,038)	$ 1,204
Net income (loss) per common share—basic and diluted	$ (0.38)	$ 0.10	$ (0.70)	$ 0.04
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders—basic and diluted	50,602	33,117	48,825	33,108

The accompanying notes are an integral part of these condensed consolidated financial statements.

Sanchez Energy Corporation

Condensed Consolidated Statement of Stockholders' Equity for the Six Months Ended June 30, 2014 (Unaudited)

(in thousands)

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-in Capital	Accumulated Deficit	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Shares	Amount			
BALANCE, December 31, 2013	3,000	$ 30	4,500	$ 45	46,369	$464	$ 867,108	$(10,338)	$ 857,309
Common shares issued	—	—	—	—	5,000	50	167,541	—	167,591
Preferred stock dividends	—	—	—	—	—	—	—	(8,312)	(8,312)
Restricted stock awards, net of forfeitures	—	—	—	—	1,337	13	(13)	—	—
Exchange of preferred stock for common stock	(1,113)	(11)	(968)	(10)	5,419	54	16,980	(17,013)	—
Stock-based compensation	—	—	—	—	—	—	25,878	—	25,878
Net loss	—	—	—	—	—	—	—	(8,713)	(8,713)
BALANCE, June 30, 2014	1,887	$ 19	3,532	$ 35	58,125	$581	$1,077,494	$(44,376)	$1,033,753

The accompanying notes are an integral part of these condensed consolidated financial statements.

Sanchez Energy Corporation

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (8,713)	$ 8,816
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	131,834	37,996
Stock-based compensation	25,878	7,712
Net (gains) losses on commodity derivative contracts	41,017	(624)
Net cash settlement received (paid) on commodity derivative contracts	(6,057)	141
Premiums paid on derivative contracts	—	(189)
Amortization of deferred financing costs	5,505	4,600
Accretion of debt discount	452	—
Deferred taxes	(4,679)	—
Changes in operating assets and liabilities:		
Accounts receivable	(14,163)	(14,360)
Other assets	(5,894)	(361)
Accounts payable	(35,237)	25,811
Accounts payable—related entities	927	(12,891)
Other payables	2,174	3,855
Accrued liabilities	8,991	8,335
Net cash provided by operating activities	142,035	68,841
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments for oil and natural gas properties	(328,673)	(175,213)
Payments for other property and equipment	(7,065)	(1,523)
Acquisitions of oil and natural gas properties	(552,380)	(291,890)
Purchases of investments	—	(25,000)
Sale of investments	—	11,591
Net cash used in investing activities	(888,118)	(482,035)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	100,000	236,000
Repayment of borrowings	(100,000)	(236,000)
Issuance of senior notes	850,000	400,000
Issuance of common stock	176,250	—
Issuance of preferred stock	—	225,000
Payments for offering costs	(8,659)	(8,439)
Financing costs	(30,856)	(18,476)
Preferred dividends paid	(8,312)	(7,556)
Purchase of common stock	—	(1,040)
Net cash provided by financing activities	978,423	589,489
Increase in cash and cash equivalents	232,340	176,295
Cash and cash equivalents, beginning of period	153,531	50,347
Cash and cash equivalents, end of period	$ 385,871	$ 226,642
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Asset retirement obligations	$ 18,229	$ 2,318
Change in accrued capital expenditures	12,106	7,775
Common stock issued in exchange for preferred stock	121,072	—
SUPPLEMENTAL DISCLOSURE:		
Cash paid for interest	$ 25,029	$ 2,020

The accompanying notes are an integral part of these condensed consolidated financial statements.

Sanchez Energy Corporation
Notes to the Condensed Consolidated Financial Statements
(Unaudited)

Note 1. Organization

Sanchez Energy Corporation (together with our consolidated subsidiaries, the "Company," "we," "our," "us" or similar terms) is an independent exploration and production company, formed in August 2011 as a Delaware corporation, focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and the Tuscaloosa Marine Shale ("TMS") in Mississippi and Louisiana. We have accumulated net leasehold acreage in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and in what we believe to be the core of the TMS. We are currently focused on the horizontal development of significant resource potential from the Eagle Ford Shale.

Note 2. Basis of Presentation and Summary of Significant Accounting Policies

The accompanying condensed consolidated financial statements are unaudited and were prepared from the Company's records. The condensed consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP" or "U.S. GAAP") for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X. The Company derived the condensed consolidated balance sheet as of December 31, 2013 from the audited financial statements filed in its Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (the "2013 Annual Report"). Because this is an interim period filing presented using a condensed format, it does not include all of the disclosures required by U.S. GAAP. These condensed consolidated financial statements should be read in connection with the consolidated financial statements and notes thereto included in the 2013 Annual Report, which contains a summary of the Company's significant accounting policies and other disclosures. In the opinion of management, these financial statements include the adjustments and accruals, all of which are of a normal recurring nature, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results to be expected for the entire year.

As of June 30, 2014, the Company's significant accounting policies are consistent with those discussed in Note 2 in the notes to the Company's consolidated financial statements contained in its 2013 Annual Report.

Use of Estimates

The condensed consolidated financial statements are prepared in conformity with U.S. GAAP, which requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, fair value accounting for acquisitions, the evaluation of unproved properties for impairment, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

Note 2. Basis of Presentation and Summary of Significant Accounting Policies (Continued)

Recent Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP.

The standard is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and have not yet determined the method by which we will adopt the standard in 2017.

Note 3. Acquisitions

Our acquisitions are accounted for under the acquisition method of accounting in accordance with Accounting Standards Codification, or ASC, Topic 805, "Business Combinations." A business combination may result in the recognition of a gain or goodwill based on the measurement of the fair value of the assets acquired at the acquisition date as compared to the fair value of consideration transferred, adjusted for purchase price adjustments. The initial accounting for acquisitions may not be complete and adjustments to provisional amounts, or recognition of additional assets acquired or liabilities assumed, may occur as more detailed analyses are completed and additional information is obtained about the facts and circumstances that existed as of the acquisition dates. The results of operations of the properties acquired in our acquisitions have been included in the condensed consolidated financial statements since the closing dates of the acquisitions.

Catarina Acquisition

On June 30, 2014, we completed our acquisition of the Catarina properties (the "Catarina acquisition") for an aggregate adjusted purchase price of \$553.5 million. The effective date of the transaction was January 1, 2014. The purchase price was funded with proceeds from the issuance of the \$850 million senior unsecured 6.125% notes due 2023 and cash on hand. The purchase price allocation for the Catarina acquisition is preliminary and is subject to further adjustments and the settlement of certain post-closing adjustments with the seller. The total purchase price was allocated to the assets

Note 3. Acquisitions (Continued)

purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved oil and natural gas properties	$428,484
Unproved properties	137,089
Other assets acquired	2,682
Fair value of assets acquired	568,255
Asset retirement obligations	(14,723)
Fair value of net assets acquired	$553,532

Cotulla Acquisition

On May 31, 2013, we completed our acquisition of the Cotulla properties (the "Cotulla acquisition") for an aggregate adjusted purchase price of $280.9 million. The effective date of the transaction was March 1, 2013.

The purchase price was funded with borrowings under the Company's First Lien Credit Agreement (defined in Note 6 "Long-Term Debt"), cash on hand, and proceeds from the Company's private placement of the Series B Convertible Perpetual Preferred Stock. The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved oil and natural gas properties	$265,466
Unproved properties	16,745
Fair value of assets acquired	282,211
Asset retirement obligations	(1,138)
Other liabilities assumed	(190)
Fair value of net assets acquired	$280,883

Wycross Acquisition

On October 4, 2013, we completed our acquisition of the Wycross properties (the "Wycross acquisition") for an aggregate adjusted purchase price of $229.6 million. The effective date of the transaction was July 1, 2013. The purchase price was funded with proceeds from the issuance of the Additional Notes (defined in Note 6 "Long-Term Debt"), the issuance of 11,040,000 shares of common

Note 3. Acquisitions (Continued)

stock, and cash on hand. The total purchase price was allocated to the assets purchased and liabilities assumed based upon their fair values on the date of acquisition as follows (in thousands):

Proved oil and natural gas properties	$215,265
Unproved properties	13,095
Other assets acquired	1,523
Fair value of assets acquired	229,883
Asset retirement obligations	(158)
Other liabilities assumed	(113)
Fair value of net assets acquired	$229,612

Pro Forma Operating Results

The following pro forma combined results for the three and six months ended June 30, 2014 and 2013 reflect the consolidated results of operations of the Company as if the Catarina acquisition and related financing had occurred on January 1, 2013 and the Wycross and Cotulla acquisitions and related financings had occurred on January 1, 2012. The pro forma information includes adjustments primarily for revenues and expenses from the acquired properties, depreciation, depletion, amortization and accretion, interest expense and debt issuance cost amortization for acquisition debt, and stock dividends for the issuance of preferred stock.

The unaudited pro forma combined financial statements give effect to the events set forth below:

- The Catarina acquisition completed on June 30, 2014.
- Issuance of the 6.125% Notes (defined in Note 6 "Long-Term Debt") to finance a portion of the Catarina acquisition, and the related adjustments to interest expense.
- The Cotulla acquisition completed on May 31, 2013.
- The increase in borrowings under the First Lien Credit Agreement to finance a portion of the Cotulla acquisition, and the related adjustments to interest expense.
- Issuance of Series B Convertible Perpetual Preferred Stock and related adjustments to preferred dividends.
- The Wycross acquisition completed on October 4, 2013.
- Issuance of the 7.75% Notes (defined in Note 6 "Long-Term Debt") to finance a portion of the Wycross acquisition, and the related adjustments to interest expense.

Note 3. Acquisitions (Continued)

- Issuance of common stock to finance a portion of the Wycross acquisition and the related effect on net income (loss) per common share (in thousands, except per share amounts).

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$216,051	$190,468	$445,563	$347,865
Net income (loss) attributable to common stockholders	$ (12,268)	$ 12,498	$ (7,920)	$ 11,028
Net income (loss) per common share, basic	$ (0.24)	$ 0.36	$ (0.16)	$ 0.32
Net income (loss) per common share, diluted	$ (0.24)	$ 0.34	$ (0.16)	$ 0.32

The pro forma combined financial information is for informational purposes only and is not intended to represent or to be indicative of the combined results of operations that the Company would have reported had the Catarina, Wycross and Cotulla acquisitions and related financings been completed as of the date set forth in this pro forma combined financial information and should not be taken as indicative of the Company's future combined results of operations. The actual results may differ significantly from that reflected in the pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the pro forma combined financial information and actual results.

Post-Acquisition Operating Results

The amounts of revenue and excess of revenues over direct operating expenses included in the Company's condensed consolidated statements of operations for the three and six months ended June 30, 2014 and 2013, for the Wycross and Cotulla acquisitions are shown in the table that follows. Direct operating expenses include lease operating expenses and production and ad valorem taxes (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues	$54,937	$8,474	$109,408	$8,474
Excess of revenues over direct operating expenses	$45,136	$4,929	$ 86,505	$4,929

Note 4. Cash and Cash Equivalents

As of June 30, 2014 and December 31, 2013, cash and cash equivalents consisted of the following (in thousands):

	June 30, 2014	December 31, 2013
Cash at banks	$135,870	$ 48,326
Money market funds	250,001	105,205
Total cash and cash equivalents	$385,871	$153,531

Note 5. Oil and Natural Gas Properties

The Company's oil and natural gas properties are accounted for using the full cost method of accounting. All direct costs and certain indirect costs associated with the acquisition, exploration and development of oil and natural gas properties are capitalized. Once evaluated, these costs, as well as the estimated costs to retire the assets, are included in the amortization base and amortized to depletion expense using the units-of-production method. Depletion is calculated based on estimated proved oil and natural gas reserves. Proceeds from the sale or disposition of oil and natural gas properties are applied to reduce net capitalized costs unless the sale or disposition causes a significant change in the relationship between costs and the estimated quantity of proved reserves.

Full Cost Ceiling Test—Capitalized costs (net of accumulated depreciation, depletion and amortization and deferred income taxes) of proved oil and natural gas properties are subject to a full cost ceiling limitation. The ceiling limits these costs to an amount equal to the present value, discounted at 10%, of estimated future net cash flows from estimated proved reserves less estimated future operating and development costs, abandonment costs (net of salvage value) and estimated related future income taxes. In accordance with SEC rules, the oil and natural gas prices used to calculate the full cost ceiling are the 12-month average prices, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements. Prices are adjusted for "basis" or location differentials. Prices are held constant over the life of the reserves. If unamortized costs capitalized within the cost pool exceed the ceiling, the excess is charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off are not reinstated for any subsequent increase in the cost center ceiling. No impairment expense was recorded for the three and six month periods ended June 30, 2014 or 2013.

Investments in unproved properties and major development projects are capitalized and excluded from the amortization base until proved reserves associated with the projects can be determined or until impairment occurs. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from amortization are transferred to the full cost pool subject to periodic amortization. The Company assesses the carrying value of its unproved properties that are not subject to amortization for impairment periodically. If the results of an assessment indicate that the properties are impaired, the amount of the asset impaired is added to the full cost pool subject to both periodic amortization and the ceiling test.

Note 6. Long-Term Debt

Long-term debt on June 30, 2014 consisted of $850 million principal amount of 6.125% senior notes maturing on January 15, 2023 (the “6.125% Notes”) and $600 million principal amount of 7.75% senior notes (the “7.75% Notes” and, together with the 6.125% Notes, the “Senior Notes”) which were issued at a discount to face value of $7.0 million, maturing on June 15, 2021. As of June 30, 2014, the Company’s long-term debt consisted of the following:

	Interest Rate	Maturity date	Amount Outstanding (in thousands)
Second amended and restated credit agreement	Variable	June 30, 2019	$ —
7.75% Notes	7.750%	June 15, 2021	600,000
6.125% Notes	6.125%	January 15, 2023	850,000
			1,450,000
Unamortized discount on Senior Notes			(6,290)
Total long-term debt			$1,443,710

Credit Facility

Previous Credit Agreement: On May 31, 2013, we and our subsidiaries, SEP Holdings III, LLC (“SEP III”), SN Marquis LLC (“SN Marquis”) and SN Cotulla Assets, LLC (“SN Cotulla”) collectively, as the borrowers, entered into a revolving credit facility which was represented by a $500 million Amended and Restated Credit Agreement with Royal Bank of Canada as the administrative agent, Capital One, National Association as the syndication agent and RBC Capital Markets as sole lead arranger and sole book runner and each of the other lenders party thereto (“First Lien Credit Agreement”). The First Lien Credit Agreement was to mature on May 31, 2018.

On May 12, 2014, the Company borrowed $100 million under the First Lien Credit Agreement. The Company used proceeds from the issuance of the 6.125% Notes to repay the $100 million outstanding.

Second Amended and Restated Credit Agreement: On June 30, 2014, the Company, as borrower, and SEP III, SN Marquis, SN Cotulla, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC as loan parties, entered into a revolving credit facility represented by a $1.5 billion Second Amended and Restated Credit Agreement, dated June 30, 2014, with Royal Bank of Canada as the administrative agent, Capital One, National Association as the syndication agent, Compass Bank and SunTrust Bank as co-documentation agents, RBC Capital Markets as sole lead arranger and sole book runner and the lenders party thereto (the “Credit Agreement”). The Company has elected an available commitment amount under the Credit Agreement of $425 million. Additionally, the Credit Agreement provides for the issuance of letters of credit, limited in the aggregate to the lesser of $50 million and the total availability thereunder. As of June 30, 2014, there were no borrowings and no letters of credit outstanding under the Credit Agreement. Availability under the Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base. The borrowing base under the

Note 6. Long-Term Debt (Continued)

Company's Credit Agreement was set at $437.5 million upon issuance of the 6.125% Notes and completion of the Catarina acquisition, with an elected commitment amount of $425 million, all of which was available for future revolver borrowings as of June 30, 2014.

The Credit Agreement matures on June 30, 2019. The borrowing base under the Credit Agreement can be subsequently redetermined up or down by the lenders based on, among other things, their evaluation of the Company's and its subsidiaries' oil and natural gas reserves. Redeterminations of the borrowing base are scheduled to occur semi-annually on April 1 and October 1 of each year, beginning on October 1, 2014. The borrowing base is also subject to reduction by 25% of the amount of the increase in the Company's net high yield debt resulting from the issuance of high yield debt.

The Company's obligations under the Credit Agreement are secured by a first priority lien on substantially all of its assets and the assets of the Company's existing and future subsidiaries not designated as "unrestricted subsidiaries," including a first priority lien on all ownership interests in existing and future subsidiaries not designated as "unrestricted subsidiaries." The obligations under the Credit Agreement are guaranteed by all of the Company's existing and future subsidiaries not designated as "unrestricted subsidiaries."

At the Company's election, borrowings under the Credit Agreement may be made on an alternate base rate or an adjusted eurodollar rate basis, plus an applicable margin. The applicable margin varies from 0.50% to 1.50% for alternate base rate borrowings and from 1.50% to 2.50% for eurodollar borrowings, depending on the utilization of the borrowing base. Furthermore, the Company is also required to pay a commitment fee on the unused committed amount at a rate varying from 0.375% to 0.50% per annum, depending on the utilization of the borrowing base.

The Credit Agreement contains various affirmative and negative covenants and events of default that limit the Company's ability to, among other things, incur indebtedness, make restricted payments, grant liens, consolidate or merge, dispose of certain assets, make certain investments, engage in transactions with affiliates, hedge transactions and make certain acquisitions. The Credit Agreement also provides for cross default between the Credit Agreement and the Company's senior unsecured notes. Furthermore, the Credit Agreement contains financial covenants that require the Company to satisfy certain specified financial ratios, including (i) current assets to current liabilities of at least 1.0 to 1.0 at all times, commencing with the fiscal quarter ending September 30, 2014 and (ii) net debt to consolidated EBITDA of not greater than 4.0 to 1.0 as of the last day of any fiscal quarter, commencing with the fiscal quarter ending September 30, 2014.

From time to time, the agents, arrangers, book runners and lenders under the Credit Agreement and their affiliates have provided, and may provide in the future, investment banking, commercial lending, hedging and financial advisory services to the Company and its affiliates in the ordinary course of business, for which they have received, or may in the future receive, customary fees and commissions for these transactions. As of June 30, 2014, the Company was in compliance with the covenants of the Credit Agreement.

Bridge Commitment: In connection with the Catarina acquisition we obtained a commitment (the "Bridge Commitment") from Royal Bank of Canada, RBC Capital Markets, Credit Suisse AG, Credit Suisse Securities (USA) LLC, Capital One, National Association and SunTrust Bank to provide, arrange, bookrun and agent, as applicable, a senior unsecured bridge facility (the "Bridge Facility"), in

Note 6. Long-Term Debt (Continued)

an aggregate amount up to $300 million (reduced by the aggregate principal amount of notes issued and sold pursuant to this offering). The Bridge Commitment was set to expire upon the earliest to occur of (a) August 19, 2014, (b) the date of execution and delivery of definitive bridge documentation by us and the lenders under the Bridge Facility or (c) the termination of the commitments by us. The Company terminated the Bridge Commitment upon the execution of the Credit Agreement on June 30, 2014 and wrote off $3.9 million in costs associated with obtaining the Bridge Commitment to interest expense at that time.

7.75% Senior Notes Due 2021

On June 13, 2013, we completed a private offering of $400 million in aggregate principal amount of our 7.75% senior notes that will mature on June 15, 2021 (the "Original Notes"). Interest is payable on each June 15 and December 15. We received net proceeds from this offering of approximately $388 million, after deducting initial purchasers' discounts and offering expenses, which we used to repay outstanding indebtedness under our credit facilities. The Original Notes are senior unsecured obligations and are guaranteed on a joint and several senior unsecured basis by, with certain exceptions, substantially all of our existing and future subsidiaries. The borrowing base under our revolving credit facility was reduced to $87.5 million upon issuance of the Original Notes, and was later increased to $400 million.

On September 18, 2013, we issued an additional $200 million in aggregate principal amount of our 7.75% senior notes due 2021 (the "Additional Notes" and, together with the Original Notes, the "7.75% Notes") in a private offering at a price to the purchasers of 96.5% of the Additional Notes. We received net proceeds from this offering of $188.8 million, after deducting the initial purchasers' discounts and estimated offering expenses of $4.2 million. The Additional Notes were issued under the same indenture as the original notes, and are therefore treated as a single class of securities under the indenture. We used the net proceeds from the offering to partially fund the Wycross acquisition completed in October 2013, a portion of the 2013 and 2014 capital budgets, and and for general corporate purposes.

The 7.75% Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured indebtedness. The 7.75% Notes rank senior in right of payment to our future subordinated indebtedness. The 7.75% Notes are effectively junior in right of payment to all of our existing and future secured debt (including under our credit facility) to the extent of the value of the assets securing such debt. The 7.75% Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by the subsidiary guarantors party to the indenture governing the 7.75% Notes. To the extent set forth in the indenture governing the 7.75% Notes, certain of our subsidiaries will be required to fully and unconditionally guarantee the 7.75% Notes on a joint and several senior unsecured basis in the future.

The indenture governing the 7.75% Notes, among other things, restricts our ability and our restricted subsidiaries' ability to: (i) incur additional indebtedness or issue preferred stock; (ii) pay dividends or make other distributions; (iii) make other restricted payments and investments; (iv) create liens on their assets; (v) incur restrictions on the ability of restricted subsidiaries to pay dividends or make certain other payments; (vi) sell assets, including capital stock of restricted subsidiaries; (vii) merge or consolidate with other entities; and (viii) enter into transactions with affiliates.

Note 6. Long-Term Debt (Continued)

We have the option to redeem all or a portion of the 7.75% Notes, at any time on or after June 15, 2017 at the applicable redemption prices specified in the indenture plus accrued and unpaid interest. We may also redeem the 7.75% Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make whole premium, together with accrued and unpaid interest and additional interest, if any, to the redemption date, at any time prior to June 15, 2017. In addition, we may redeem up to 35% of the 7.75% Notes prior to June 15, 2016 under certain circumstances with an amount equal to the net cash proceeds from one or more equity offerings at the redemption price specified in the indenture. We may also be required to repurchase the 7.75% Notes upon a change of control or if we sell certain of our assets.

6.125% Senior Notes Due 2023

On June 27, 2014, the Company completed a private offering to eligible purchasers of $850 million in aggregate principal amount of the Company's 6.125% Notes. Interest is payable on each July 15 and January 15. The Company received net proceeds from this offering of approximately $829 million, after deducting initial purchasers' discounts and estimated offering expenses, which the Company used to repay all of the $100 million in borrowings outstanding under its First Lien Credit Agreement and to finance a portion of the purchase price of the Catarina acquisition. We intend to use the remaining proceeds from the offering to fund a portion of the remaining 2014 capital budget and for general corporate purposes. The 6.125% Notes are the senior unsecured obligations of the Company and are guaranteed on a joint and several senior unsecured basis by, with certain exceptions, substantially all of the Company's existing and future subsidiaries.

The 6.125% Notes are the senior unsecured obligations of the Company and rank equally in right of payment with all of the Company's existing and future senior unsecured indebtedness. The 6.125% Notes rank senior in right of payment to the Company's future subordinated indebtedness. The 6.125% Notes are effectively junior in right of payment to all of the Company's existing and future secured debt (including under the First Lien Credit Agreement) to the extent of the value of the assets securing such debt. The 6.125% Notes are fully and unconditionally guaranteed on a joint and several senior unsecured basis by the subsidiary guarantors party to the indenture governing the 6.125% Notes. To the extent set forth in the indenture governing the 6.125% Notes, certain subsidiaries of the Company will be required to fully and unconditionally guarantee the 6.125% Notes on a joint and several senior unsecured basis in the future.

The indenture governing the 6.125% Notes, among other things, restricts the Company's ability and the ability of the Company's restricted subsidiaries to: (i) incur, assume or guarantee additional indebtedness or issue certain types of equity securities; (ii) pay distributions on, purchase or redeem shares or purchase or redeem subordinated debt; (iii) make certain investments; (iv) enter into certain transactions with affiliates; (v) create or incur liens on their assets; (vi) sell assets; (vii) consolidate, merge or transfer all or substantially all of their assets; (viii) restrict distributions or other payments from the Company's restricted subsidiaries; and (ix) designate subsidiaries as unrestricted subsidiaries.

The Company has the option to redeem all or a portion of the 6.125% Notes, at any time on or after July 15, 2018 at the applicable redemption prices specified in the indenture plus accrued and unpaid interest. The Company may also redeem the 6.125% Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make whole premium, together with accrued and

Note 6. Long-Term Debt (Continued)

unpaid interest and additional interest, if any, to the redemption date, at any time prior to July 15, 2018. In addition, the Company may redeem up to 35% of the 6.125% Notes prior to July 15, 2017 under certain circumstances with the net cash proceeds from certain equity offerings at the redemption price specified in the indenture. The Company may also be required to repurchase the 6.125% Notes upon a change of control.

Note 7. Derivative Instruments

To reduce the impact of fluctuations in oil and natural gas prices on the Company's revenues, or to protect the economics of property acquisitions, the Company periodically enters into derivative contracts with respect to a portion of its projected oil and natural gas production through various transactions that fix or, through options, modify the future prices to be realized. These transactions may include price swaps whereby the Company will receive a fixed price for its production and pay a variable market price to the contract counterparty. Additionally, the Company may enter into collars, whereby it receives the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. In addition, the Company enters into option transactions, such as puts or put spreads, as a way to manage its exposure to fluctuating prices. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never the Company's intention to enter into derivative contracts for speculative trading purposes.

Under ASC Topic 815, "Derivatives and Hedging," all derivative instruments are recorded on the condensed consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. The Company will net derivative assets and liabilities for counterparties where it has a legal right of offset. Changes in the derivatives' fair values are recognized currently in earnings since the Company has elected not to designate its current derivative contracts as hedges.

As of June 30, 2014, the Company had the following crude oil swaps, collars, and put spreads covering anticipated future production:

Contract Period	Derivative Instrument	Barrels	Purchased	Sold	Pricing Index
July 1, 2014 - December 31, 2014	Swap	138,000	$92.00	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	138,000	$91.35	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	138,000	$92.45	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	184,000	$95.45	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	184,000	$93.25	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$89.65	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$90.05	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$88.48	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$88.35	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Collar	184,000	$90.00	$99.10	NYMEX WTI
July 1, 2014 - December 31, 2014	Put Spread	184,000	$90.00	$75.00	NYMEX WTI

Note 7. Derivative Instruments (Continued)

As of June 30, 2014, the Company had the following crude oil enhanced swaps covering anticipated future production:

Contract Period	Barrels	Purchased	Put	Pricing Index
January 1, 2015 - December 31, 2015	365,000	$91.46	$75.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$93.13	$75.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$92.20	$75.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$91.46	$75.00	NYMEX WTI

As of June 30, 2014, the Company had the following natural gas swaps and collars covering anticipated future production:

Contract Period	Derivative Instrument	Mmbtu	Purchased	Sold	Pricing Index
July 1, 2014 - December 31, 2014	Swap	368,000	$4.23	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Swap	368,000	$4.23	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Swap	368,000	$4.24	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Swap	368,000	$4.61	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Collar	368,000	$4.00	$4.50	NYMEX NG

As of June 30, 2014, the Company had the following natural gas enhanced swaps covering anticipated future production:

Contract Period	Mmbtu	Purchased	Put	Pricing Index
January 1, 2015 - December 31, 2015	2,190,000	$4.44	$3.75	NYMEX NG
January 1, 2015 - December 31, 2015	1,095,000	$4.40	$3.75	NYMEX NG
January 1, 2015 - December 31, 2015	730,000	$4.50	$3.75	NYMEX NG

As of June 30, 2014, the Company had the following three-way crude oil collar contracts that combine a long and short put with a short call:

Contract Period	Barrels	Short Put	Long Put	Short Call	Pricing Index
July 1, 2014 - December 31, 2014	276,000	$65.00	$85.00	$102.25	NYMEX WTI
July 1, 2014 - December 31, 2014	184,000	$75.00	$95.00	$107.50	LLS
July 1, 2014 - December 31, 2014	184,000	$75.00	$90.00	$ 96.22	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$70.00	$85.00	$ 95.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$70.00	$85.00	$ 95.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$70.00	$85.00	$ 94.75	NYMEX WTI

The Company deferred the payment of premiums associated with certain of its oil derivative instruments. On June 30, 2014 and December 31, 2013, the balances of deferred payments totaled $5.6 million. These premiums are being paid to the counterparty with each monthly settlement beginning July 2014.

Note 7. Derivative Instruments (Continued)

The following table sets forth a reconciliation of the changes in fair value of the Company's commodity derivatives for the six months ended June 30, 2014 and the year ended December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013
Beginning fair value of commodity derviatives	$ (3,397)	$ 2,145
Net losses on crude oil derivatives	(40,323)	(16,891)
Net losses on natural gas derivatives	(694)	(47)
Net settlements on derivative contracts:		
Crude oil	7,344	5,755
Natural gas	673	32
Net premiums incurred on derivative contracts:		
Crude oil	—	5,609
Ending fair value of commodity derivatives	$(36,397)	$ (3,397)

Balance Sheet Presentation

The Company's derivatives are presented on a net basis as "Fair value of derivative instruments" on the condensed consolidated balance sheets. The following information summarizes the gross fair values of derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on the Company's condensed consolidated balance sheets (in thousands):

	June 30, 2014		
	Gross Amount of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts Presented in the Condensed Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 1,202	$(1,138)	$ 64
Long-term asset	2,025	(1,917)	108
Total asset	$ 3,227	$(3,055)	$ 172
Offsetting Derivative Liabilities:			
Current liability	$(28,286)	$ 1,138	$(27,148)
Long-term liability	(11,338)	1,917	(9,421)
Total liability	$(39,624)	$ 3,055	$(36,569)

Note 7. Derivative Instruments (Continued)

	December 31, 2013		
	Gross Amount of Recognized Assets	Gross Amounts Offset in the Condensed Consolidated Balance Sheets	Net Amounts Presented in the Condensed Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 4,049	$(4,049)	$ —
Long-term asset	3,310	(2,006)	1,304
Total asset	$ 7,359	$(6,055)	$ 1,304
Offsetting Derivative Liabilities:			
Current liability	$ (8,672)	$ 4,049	$(4,623)
Long-term liability	(2,084)	2,006	(78)
Total liability	$(10,756)	$ 6,055	$(4,701)

Note 8. Fair Value of Financial Instruments

Measurements of fair value of derivative instruments are classified according to the fair value hierarchy, which prioritizes the inputs to the valuation techniques used to measure fair value. Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that can be valued using observable market data. Substantially all of these inputs are observable in the marketplace throughout the term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: 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 (i.e. supported by little or no market activity). The valuation models used to value derivatives associated with the Company's oil and natural gas production are primarily industry standard models that consider various inputs including: (a) quoted forward prices for commodities, (b) time value and (c) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Although third party quotes are utilized to assess the reasonableness of the prices and valuation techniques, there is not sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the

Note 8. Fair Value of Financial Instruments (Continued)

fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Fair Value on a Recurring Basis

The following tables set 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 as of June 30, 2014 and December 31, 2013 (in thousands):

	As of June 30, 2014			
	Active Market for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents:				
Money market funds	$250,001	$ —	$ —	$250,001
Oil derivative instruments:				
Swaps	—	(19,434)	—	(19,434)
Enhanced Swaps	—	—	(7,785)	(7,785)
Three-way collars	—	—	(8,203)	(8,203)
Collars	—	—	(954)	(954)
Puts	—	—	14	14
Gas derivative instruments:				
Swaps	—	(189)	—	(189)
Enhanced Swaps	—	—	205	205
Collars	—	—	(51)	(51)
Total	$250,001	$(19,623)	$(16,774)	$213,604

	As of December 31, 2013			
	Active Market for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Total Carrying Value
Cash and cash equivalents:				
Money market funds	$105,205	$ —	$ —	$105,205
Oil derivative instruments:				
Swaps	—	(2,841)	—	(2,841)
Three-way collars	—	—	(398)	(398)
Collars	—	—	3	3
Puts	—	—	(146)	(146)
Gas derivative instruments:				
Swaps	—	(37)	—	(37)
Collars	—	—	22	22
Total	$105,205	$(2,878)	$(519)	$101,808

Financing arrangements: The Company filed a registration statement for its 7.75% Notes in an exchange offer filed with the SEC, which became effective on June 20, 2014, creating an active market for the 7.75% Notes, and as such, results in a Level 1 fair value measurement. The estimated fair value of the 7.75% Notes was $660 million as of June 30, 2014, and was calculated using quoted market prices based on trades of such debt as of that date. The Company uses a market approach to

Note 8. Fair Value of Financial Instruments (Continued)

determine fair value of its unregistered 6.125% Notes using observable market data, which results in a Level 2 fair value measurement. The estimated fair value of the 6.125% Notes was $875.5 million as of June 30, 2014, and was calculated using quoted market prices based on trades of such debt as of that date.

Financial Instruments: The Level 1 instruments presented in the table above consist of money market funds included in cash and cash equivalents on the Company's condensed consolidated balance sheet as of June 30, 2014 and December 31, 2013. The Company's money market funds represent cash equivalents backed by the assets of high-quality banks and financial institutions. The Company identified the money market funds as Level 1 instruments due to the fact that the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 2 instruments presented in the table above consist of commodity derivatives. These asset values can be closely approximated using simple models and extrapolation methods using known, observable prices as parameters.

The Company's derivative instruments, which consist of swaps, enhanced swaps, collars and puts, are classified as either Level 2 or Level 3 in the table above. The fair values of the Company's derivatives are based on third party pricing models which utilize inputs that are either readily available in the public market, such as forward curves, or can be corroborated from active markets of broker quotes. These values are then compared to the values given by the Company's counterparties for reasonableness. Since swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. The Company's enhanced swaps, puts, collars and three-way collars include some level of unobservable input, such as volatility curves, and are therefore classified as Level 3. Derivative instruments are also subject to the risk that counterparties will be unable to meet their obligations. Such non- performance risk is considered in the valuation of the Company's derivative instruments, but to date has not had a material impact on estimates of fair values. Significant changes in the quoted forward prices for commodities and changes in market volatility generally lead to corresponding changes in the fair value measurement of the Company's derivative instruments.

The fair values of the Company's derivative instruments classified as Level 3 as of June 30, 2014 and December 31, 2013 were ($16.8) million and ($0.5) million, respectively. The significant unobservable inputs for Level 3 contracts include unpublished forward prices of commodities, market volatility and credit risk of counterparties. Changes in these inputs will impact the fair value measurement of the Company's derivative contracts.

Note 8. Fair Value of Financial Instruments (Continued)

The following table sets forth a reconciliation of changes in the fair value of the Company's derivative instruments classified as Level 3 in the fair value hierarchy (in thousands):

	Significant Unobservable Inputs (Level 3)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Beginning balance	$ (2,516)	$ 932	$ (519)	$3,015
Total gains (losses) included in earnings	(15,391)	2,165	(17,800)	151
Net settlements on derivative contracts	1,133	(94)	1,545	(163)
Ending balance	$(16,774)	$3,003	$(16,774)	$3,003
Gains (losses) included in earnings related to derivatives still held as of June 30, 2014 and 2013	$(14,259)	$2,526	$(16,255)	$ 893

Fair Value on a Non-Recurring Basis

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. Fair-value measurements of assets acquired and liabilities assumed in business combinations are based on inputs that are not observable in the market and thus represent Level 3 inputs. The fair value of acquired properties is based on market and cost approaches. Our purchase price allocations for the Catarina, Cotulla and Wycross acquisitions are presented in Note 3. Liabilities assumed include asset retirement obligations existing at the date of acquisition. The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligations is presented in Note 9.

In connection with the exchange agreements entered into in February and May 2014 by the Company with certain holders of the Company's Series A Preferred Stock and Series B Preferred Stock, the Company issued common stock according to the conversion rate pursuant to each agreement and additional shares to induce the holders of the preferred stock to convert prior to the date the Company could mandate conversion. The fair value of the common stock issued is based on the price of the Company's common stock on the date of issuance. As there is an active market for the Company's common stock, the Company has designated this fair value measurement as Level 1. A detailed description of the Company's common stock and preferred stock issuances and redemptions is presented in Note 12.

Note 9. Asset Retirement Obligations

Asset retirement obligations represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, well life, inflation and credit-adjusted risk-free rate. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset. Upon settlement of the liability, any gain or loss is treated as an adjustment to the full cost pool.

Note 9. Asset Retirement Obligations (Continued)

The changes in the asset retirement obligation for the six months ended June 30, 2014 and the year ended December 31, 2013 were as follows (in thousands):

	2014	2013
Abandonment liability, beginning of period	$ 4,130	$ 546
Liabilities incurred during period	1,450	1,122
Acquisitions	14,723	1,296
Revisions	2,056	968
Accretion expense	267	198
Abandonment liability, end of period	$22,626	$4,130

During the first quarter of 2014, the Company reviewed its asset retirement obligation estimates. A quote was obtained from a third party that indicated anticipated costs for future abandonment had increased from previous estimates. As a result, the Company increased its estimates of future asset retirement obligations by $2.1 million to reflect anticipated increased costs for plugging and abandonment. During the first quarter of 2013, the Company performed a similar exercise to update its asset retirement obligation estimates. As a result, the Company increased its estimates of future asset retirement obligations by $1.0 million to reflect anticipated increased costs for plugging and abandonment.

Note 10. Related Party Transactions

Sanchez Oil & Gas Corporation (“SOG”), headquartered in Houston, Texas, is a private full service oil and natural gas company engaged in the exploration and development of oil and natural gas primarily in the South Texas and onshore Gulf Coast areas on behalf of its affiliates. The Company refers to SOG, Sanchez Energy Partners I, LP (“SEP I”), and their affiliates (but excluding the Company) collectively as the “Sanchez Group.”

The Company does not have any employees. On December 19, 2011 it entered into a services agreement with SOG pursuant to which specified employees of SOG provide certain services with respect to the Company’s business under the direction, supervision and control of SOG. Pursuant to this arrangement, SOG performs centralized corporate functions for the Company, such as general and administrative services, geological, geophysical and reserve engineering, lease and land administration, marketing, accounting, operational services, information technology services, compliance, insurance maintenance and management of outside professionals. The Company compensates SOG for the services at a price equal to SOG’s cost of providing such services, including all direct costs and indirect administrative and overhead costs (including the allocable portion of salary, bonus, incentive compensation and other amounts paid to persons that provide the services on SOG’s behalf) allocated in accordance with SOG’s regular and consistent accounting practices, including for any such costs arising from amounts paid directly by other members of the Sanchez Group on SOG’s behalf or borrowed by SOG from other members of the Sanchez Group, in each case, in connection with the performance by SOG of services on the Company’s behalf. The Company also reimburses SOG for sales, use or other taxes, or other fees or assessments imposed by law in connection with the provision of services to the Company (other than income, franchise or margin taxes measured by SOG’s net

Note 10. Related Party Transactions (Continued)

income or margin and other than any gross receipts or other privilege taxes imposed on SOG) and for any costs and expenses arising from or related to the engagement or retention of third party service providers.

Salaries and associated benefit costs of SOG employees are allocated to the Company based on the actual time spent by the professional staff on the properties and business activities of the Company. General and administrative costs, such as office rent, utilities, supplies, and other overhead costs, are allocated to the Company based on a fixed percentage that is reviewed quarterly and adjusted, if needed, based on the activity levels of services provided to the Company. General and administrative costs that are specifically incurred by or for the specific benefit of the Company are charged directly to the Company. Expenses allocated to the Company for general and administrative expenses for the three and six months ended June 30, 2014 and 2013 are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Administrative fees	$6,330	$3,479	$12,462	$5,902
Third party expenses	1,776	104	2,683	2,284
Total included in general and administrative expenses	$8,106	$3,583	$15,145	$8,186

As of June 30, 2014 and December 31, 2013, the Company had a net payable to SOG and other members of the Sanchez Group of $1.9 million and $1.0 million, respectively, which are reflected as "Accounts payable—related entities" in the condensed consolidated balance sheets. The net payables consist primarily of obligations for general and administrative costs due to SOG and revenue payable to affiliated entities.

TMS Asset Purchase

In August 2013, we acquired approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS for cash and shares of our common stock plus an initial 3 gross (1.5 net) well drilling carry. In connection with the TMS transactions, we established an Area of Mutual Interest ("AMI") in the TMS with SR Acquisition I, LLC ("SR"), a subsidiary of our affiliate Sanchez Resources, LLC ("Sanchez Resources"). Sanchez Resources is indirectly owned, in part, by our President and Chief Executive Officer and the Executive Chairman of the Company's Board of Directors (the "Board"), who each also serve on our Board. Additionally, Eduardo Sanchez, Patricio Sanchez and Ana Lee Sanchez Jacobs, each an immediate family member of our President and Chief Executive Officer and the Executive Chairman of our Board, collectively, either directly or indirectly, own a majority of the equity interests of Sanchez Resources. Sanchez Resources is managed by Eduardo Sanchez, who is the brother of our President and Chief Executive Officer and the son of our Executive Chairman of the Board.

As part of the transaction, we acquired all of the working interests in the AMI owned at closing from three sellers (two third parties and one related party of the Company, SR) resulting in our

Note 10. Related Party Transactions (Continued)

owning an undivided 50% working interest across the AMI through the TMS. The AMI holds rights to approximately 115,000 gross acres and 80,000 net acres.

Total consideration for the TMS transactions consisted of approximately $70 million in cash and the issuance of 342,760 common shares of the Company, valued at $7.5 million. The cash consideration provided to SR was $14.4 million. The acquisitions were accounted for as the purchase of assets at cost on the acquisition date.

We have also committed, as a part of the total consideration, to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we do not fulfill our obligations in a timely manner with regard to the initial TMS well commitment, we must re-assign the working interests acquired from SR. At the point that the minimum commitment is met, we will have fully paid for and earned all of our rights to the TMS acreage. If we desire, at our sole discretion, to continue drilling within the AMI after fulfilling the minimum well commitment, we would be required to carry SR in an additional 3 gross (1.5 net) TMS wells.

Note 11. Accrued Liabilities

The following information summarizes accrued liabilities as of June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013
Capital expenditures	$ 98,989	$ 86,883
General and administrative costs	7,017	550
Production taxes	3,017	2,903
Ad valorem taxes	4,385	981
Lease operating expenses	7,772	8,977
Interest payable	2,372	2,161
Total accrued liabilities	$123,552	$102,455

Note 12. Stockholders' Equity

Common Stock Offerings—On September 18, 2013, the Company completed a public offering of 11,040,000 shares of common stock (including 1,440,000 shares purchased pursuant to the full exercise of the underwriters' overallotment option), at an issue price of $23.00 per share. The Company received net proceeds from this offering of $241.4 million, after deducting underwriters' fees and offering expenses of $12.5 million. The Company used the net proceeds from the offering to partially fund the Wycross acquisition completed in October 2013 and a portion of the 2013 capital budget, and intends to use the remaining proceeds to fund a portion of the 2014 capital budget and for general corporate purposes.

On June 12, 2014, the Company completed a public offering of 5,000,000 shares of common stock, at an issue price of $35.25 per share. The Company received net proceeds from this offering of $167.6 million, after deducting underwriters' fees and offering expenses of $8.7 million. The Company

Note 12. Stockholders' Equity (Continued)

intends to use the net proceeds from the offering to partially fund the 2014 capital budget and for general corporate purposes.

Series A Convertible Perpetual Preferred Stock Offering—On September 17, 2012, the Company completed a private placement of 3,000,000 shares of Series A Convertible Perpetual Preferred Stock, which were sold to a group of qualified institutional buyers pursuant to the Rule 144A exemption from registration under the Securities Act of 1933, as amended. The issue price of each share of the Series A Convertible Perpetual Preferred Stock was $50.00. The Company received net proceeds from the private placement of $144.5 million, after deducting initial purchasers' discounts and commissions and offering costs payable by the Company of $5.5 million. Pursuant to the Certificate of Designations for the Series A Convertible Perpetual Preferred Stock, each share of Series A Convertible Perpetual Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.3250 shares of common stock per share of Series A Convertible Perpetual Preferred Stock (which is equal to an initial conversion price of $21.51 per share of common stock) and is subject to specified adjustments. Based on the initial conversion price, 4,772,086 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Series A Convertible Perpetual Preferred Stock.

The annual dividend on each share of Series A Convertible Perpetual Preferred Stock is 4.875% on the liquidation preference of $50.00 per share and is payable quarterly, in arrears, on each January 1, April 1, July 1 and October 1, when, as and if declared by the Board. No dividends were accrued or accumulated prior to September 17, 2012. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. As of June 30, 2014, all dividends accumulated through that date had been paid.

Except as required by law or the Company's Amended and Restated Certificate of Incorporation, holders of the Series A Convertible Perpetual Preferred Stock will have no voting rights unless dividends fall into arrears for six or more quarterly periods (whether or not consecutive). In that event and until such arrearage is paid in full, the holders of the Series A Convertible Perpetual Preferred Stock and the holders of the Series B Convertible Perpetual Preferred Stock, voting as a single class, will be entitled to elect two directors and the number of directors on the Board will increase by that same number.

At any time on or after October 5, 2017, the Company may at its option cause all outstanding shares of the Series A Convertible Perpetual Preferred Stock to be automatically converted into common stock at the conversion price, if, among other conditions, the closing sale price (as defined) of the Company's common stock equals or exceeds 130% of the conversion price for a specified period prior to the conversion.

If a holder elects to convert shares of Series A Convertible Perpetual Preferred Stock upon the occurrence of certain specified fundamental changes, the Company will be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option time value of the shares of Series A Convertible Perpetual Preferred Stock as a result of the fundamental change.

Note 12. Stockholders' Equity (Continued)

Series B Convertible Perpetual Preferred Stock Offering—On March 26, 2013, the Company completed a private placement of 4,500,000 shares of Series B Convertible Perpetual Preferred Stock. The issue price of each share of the Series B Convertible Perpetual Preferred Stock was $50.00. The Company received net proceeds from the private placement of $216.6 million, after deducting placement agent's fees and offering costs of $8.4 million.

Each share of Series B Convertible Perpetual Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.3370 shares of common stock per share of Series B Convertible Perpetual Preferred Stock (which is equal to an initial conversion price of $21.40 per share of common stock) and is subject to specified adjustments. Based on the initial conversion price, 8,747,742 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Series B Convertible Perpetual Preferred Stock.

The annual dividend on each share of Series B Convertible Perpetual Preferred Stock is 6.500% on the liquidation preference of $50.00 per share and is payable quarterly, in arrears, on each January 1, April 1, July 1 and October 1, when, as and if declared by the Board. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. As of June 30, 2014, all dividends accumulated through that date had been paid.

Except as required by law or the Company's Amended and Restated Certificate of Incorporation, holders of the Series B Convertible Perpetual Preferred Stock will have no voting rights unless dividends fall into arrears for six or more quarterly periods (whether or not consecutive). In that event and until such arrearage is paid in full, the holders of the Series B Convertible Perpetual Preferred Stock and the holders of the Series A Convertible Perpetual Preferred Stock, voting as a single class, will be entitled to elect two directors and the number of directors on the Board will increase by that same number.

At any time on or after April 6, 2018, the Company may at its option cause all outstanding shares of the Series B Convertible Preferred Stock to be automatically converted into common stock at the conversion price, if, among other conditions, the closing sale price (as defined) of the Company's common stock equals or exceeds 130% of the conversion price for a specified period prior to the conversion.

If a holder elects to convert shares of Series B Convertible Perpetual Preferred Stock upon the occurrence of certain specified fundamental changes, the Company will be obligated to deliver an additional number of shares above the applicable conversion rate to compensate the holder for lost option time value of the shares of Series B Convertible Perpetual Preferred Stock as a result of the fundamental change.

Preferred Stock Exchange—On February 12, 2014 and February 13, 2014, the Company entered into exchange agreements with certain holders (the "February 2014 Holders") of the Company's Series A Convertible Perpetual Preferred Stock, and of Series B Convertible Perpetual Preferred Stock, pursuant to which such holders agreed to exchange an aggregate of (i) 947,490 shares of Series A Convertible Perpetual Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 2,425,574 shares of the Company's common stock, and (ii) 756,850 shares of the Series B Convertible Perpetual Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 2,021,066 shares of common stock.

Note 12. Stockholders' Equity (Continued)

Additionally, on May 29, 2014, the Company entered into exchange agreements with certain holders (the "May 2014 Holders", and together with the February 2014 Holders, the "Holders") of the Company's Series A Convertible Perpetual Preferred Stock, and of Series B Convertible Perpetual Preferred Stock, pursuant to which such holders agreed to exchange an aggregate of (i) 166,025 shares of Series A Convertible Perpetual Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 418,715 shares of the Company's common stock, and (ii) 210,820 shares of the Series B Convertible Perpetual Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 553,980 shares of common stock.

Since the Holders were not entitled to any consideration over and above the initial conversion rates of 2.325 and 2.337 common shares for each preferred share exchanged for Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock, respectively, any consideration is considered an inducement for the Holders to convert earlier than the Company could have forced conversion.

The Company has determined the fair value of consideration transferred to the Holders and the fair value of consideration transferrable pursuant to the original conversion terms. The $13.9 million and $3.1 million excess of the fair value of the shares of common stock issued over the carrying value of the Series A Preferred Stock and Series B Preferred Stock redeemed for the February and May conversions, respectively, has been reflected as an additional preferred stock dividend, that is, as a reduction of retained earnings to arrive at net income attributable to common shareholders in our condensed consolidated financial statements.

Note 12. Stockholders' Equity (Continued)

Earnings (Loss) Per Share—The following table shows the computation of basic and diluted net income (loss) per share for the three and six months ended June 30, 2014 and 2013 (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$(12,158)	$ 8,890	$ (8,713)	$ 8,816
Less:				
Preferred stock dividends	(7,132)	(5,484)	(25,325)	(7,556)
Net income allocable to participating securities(1)	—	(159)	—	(56)
Net income (loss) attributable to common stockholders	$(19,290)	$ 3,247	$(34,038)	$ 1,204
Weighted average number of unrestricted outstanding common shares used to calculate basic net income (loss) per share	50,602	33,117	48,825	33,108
Dilutive shares(2)(3)	—	—	—	—
Denominator for diluted net income (loss) per common share	50,602	33,117	48,825	33,108
Net income (loss) per common share—basic and diluted	$ (0.38)	$ 0.10	$ (0.70)	$ 0.04

(1) For the three and six months ended June 30, 2014, no losses were allocated to participating restricted stock because such securities do not have a contractual obligation to share in the Company's losses.

(2) The three and six months ended June 30, 2014 excludes 423,771 and 829,375 shares of weighted average restricted stock and 13,253,510 and 14,502,257 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive.

(3) The three and six months ended June 30, 2013 excludes 208,130 and 539,141 shares of weighted average restricted stock and 17,491,500 and 12,466,950 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive.

Note 13. Stock-Based Compensation

At the Annual Meeting of Stockholders of the Company held on May 23, 2012, the Company's stockholders approved the Sanchez Energy Corporation Amended and Restated 2011 Long Term Incentive Plan (the "LTIP"). The Board had previously approved the amendment of the LTIP on April 16, 2012, subject to stockholder approval.

Note 13. Stock-Based Compensation (Continued)

The Company's directors and consultants as well as employees of the Sanchez Group who provide services to the Company are eligible to participate in the LTIP. Awards to participants may be made in the form of restricted shares, phantom shares, share options, share appreciation rights and other share-based awards. The maximum number of shares that may be delivered pursuant to the LTIP is limited to 15% of the Company's issued and outstanding shares of common stock. This maximum amount automatically increases to 15% of the issued and outstanding shares of common stock immediately after each issuance by the Company of its common stock, unless the Board determines to increase the maximum number of shares of common stock by a lesser amount. Shares withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP. In addition, if an award is forfeited, canceled, exercised, paid or otherwise terminates or expires without the delivery of shares, the shares subject to such award are then available for new awards under the LTIP. Shares delivered pursuant to awards under the LTIP may be newly issued shares, shares acquired by the Company in the open market, shares acquired by the Company from any other person, or any combination of the foregoing.

The LTIP is administered by the Board. The Board may terminate or amend the LTIP at any time with respect to any shares for which a grant has not yet been made. The Board has the right to alter or amend the LTIP or any part of the LTIP from time to time, including increasing the number of shares that may be granted, subject to shareholder approval as may be required by the exchange upon which the common shares are listed at that time, if any. No change may be made in any outstanding grant that would materially reduce the benefits of the participant without the consent of the participant. The LTIP will expire upon its termination by the Board or, if earlier, when no shares remain available under the LTIP for awards. Upon termination of the LTIP, awards then outstanding will continue pursuant to the terms of their grants.

The Company records stock-based compensation expense for awards granted to its directors (for their services as directors) in accordance with the provisions of ASC 718, "Compensation—Stock Compensation." Stock- based compensation expense for these awards is based on the grant-date fair value and recognized over the vesting period using the straight-line method.

Awards granted to employees of the Sanchez Group (including those employees of the Sanchez Group who also serve as the Company's officers) and consultants in exchange for services are considered awards to non-employees and the Company records stock-based compensation expense for these awards at fair value in accordance with the provisions of ASC 505-50, "Equity-Based Payments to Non-Employees." For awards granted to non-employees, the Company records compensation expenses equal to the fair value of the stock-based award at the measurement date, which is determined to be the earlier of the performance commitment date or the service completion date. Compensation expense for unvested awards to non-employees is revalued at each period end and is amortized over the vesting period of the stock-based award. Stock-based payments are measured based on the fair value of the equity instruments granted, as it is more determinable than the value of the services rendered.

Note 13. Stock-Based Compensation (Continued)

For the restricted stock awards granted to non-employees, stock-based compensation expense is based on fair value remeasured at each reporting period and recognized over the vesting period using the straight-line method. Compensation expense for these awards will be revalued at each period end until vested.

The Company recognized the following stock-based compensation expense for the periods indicated which is reflected as general and administrative expense in the condensed consolidated statements of operations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Restricted stock awards, directors	$ 262	$ 138	$ 560	$ 231
Restricted stock awards, non-employees	15,681	4,440	25,318	7,481
Total stock-based compensation expense	$15,943	$4,578	$25,878	$7,712

Based on the $37.59 per share closing price of the Company's common stock on June 30, 2014, there was $68.0 million of unrecognized compensation cost related to these non-vested restricted shares outstanding. The cost is expected to be recognized over an average period of approximately 1.9 years.

A summary of the status of the non-vested shares as of June 30, 2014 is presented below (in thousands):

	Number of Non-Vested Shares
Non-vested common stock as of December 31, 2013	1,758
Granted	1,646
Vested	(636)
Forfeited	(309)
Non-vested common stock as of June 30, 2014	2,459

As of June 30, 2014, approximately 4.9 million shares remain available for future issuance to participants.

Note 14. Income Taxes

The Company's estimated annual effective income tax rates are used to allocate expected annual income tax expense to interim periods. The rates are determined based on the ratio of estimated annual income tax expense to estimated annual income before income taxes by taxing jurisdiction, except for discrete items, which are significant, unusual or infrequent items for which income taxes are computed and recorded in the interim period in which the specific transaction occurs. The estimated annual effective income tax rates are applied to the year-to-date income before income taxes by taxing jurisdiction to determine the income tax expense allocated to the interim period. The Company updates its estimated annual effective income tax rate at the end of each quarterly period considering the

Note 14. Income Taxes (Continued)

geographic mix of income based on the tax jurisdictions in which the Company operates. Actual results that are different from the assumptions used in estimating the annual effective income tax rate will impact future income tax expense. The difference between the statutory federal income taxes calculated using a U.S. Federal statutory corporate income tax rate of 35% and the Company's effective tax rate of 34.9% for the six months ended June 30, 2014 is related to non-deductible general and administrative expenses recorded during the period. Our effective tax rate for the three months ended June 30, 2014 was equal to the statutory rate of 35%. The Company's effective tax rate for the three and six months ended June 30, 2013 was 0%, due to the change in valuation allowance recorded against net deferred income tax assets.

As of June 30, 2014, the Company had estimated net operating loss carryforwards of $660.5 million, which will begin to expire in 2031.

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of the deferred income tax assets will be realized. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, both positive and negative, historical and prospective, with greater weight given to historical evidence, it is more likely than not that the deferred tax assets will be realized and therefore reversed the valuation allowance against its net deferred tax asset in the third quarter of 2013. There was no change in the valuation allowance during the three and six months ended June 30, 2014. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

As of June 30, 2014, the Company had no material uncertain tax positions.

Note 15. Commitments and Contingencies

From time to time, the Company may be involved in lawsuits that arise in the normal course of its business. On December 4, 13 and 16, 2013, three derivative actions were filed in the Court of Chancery of the State of Delaware against the Company, certain of its officers and directors, Sanchez Resources, Altpoint Capital Partners LLC and Altpoint Sanchez Holdings, LLC (the "Consolidated Derivative Actions," Friedman v. A.R. Sanchez, Jr. et al., No. 9158; City of Roseville Employees' Retirement System v. A.R. Sanchez, Jr. et al., No. 9132; and Delaware County Employees Retirement Fund v. A.R. Sanchez, Jr. et al., No. 9165).

On December 20, 2013, the Consolidated Derivative Actions were consolidated, co-lead counsel for the plaintiffs was appointed and the plaintiffs were ordered to file an amended consolidated complaint (In re Sanchez Energy Derivative Litigation, Consolidated C.A. No. 9132-VCG, hereinafter, the "Delaware Derivative Action"). On January 28, 2014, a verified consolidated stockholder derivative complaint was filed. The Consolidated Derivative Actions concern the Company's purchase of working interests in the TMS from Sanchez Resources. Plaintiffs allege breaches of fiduciary duty against the individual defendants as directors of the Company; breaches of fiduciary duty against Antonio R. Sanchez, III as an executive director of the Company; aiding and abetting breaches of fiduciary duty against Sanchez Resources, Eduardo Sanchez, Altpoint Capital Partners LLC and Altpoint Sanchez Holdings, LLC; and unjust enrichment against A.R. Sanchez, Jr. and Antonio R. Sanchez, III. All of

Note 15. Commitments and Contingencies (Continued)

the defendants filed a motion to dismiss on April 1, 2014. Briefing concerning the motions to dismiss concluded on June 27, 2014, but no ruling has been made at this time. The Consolidated Derivative Actions are in their preliminary stages, and the Company is unable to reasonably predict an outcome or to reasonably estimate a range of possible loss.

On January 9, 2014, a derivative action was filed in 333rd district court in Harris County, Texas against the Company and certain of its officers and directors, styled Martin v. Sanchez, No. 2014-01028 (333rd Dist. Harris County, Texas) (the "Texas State Derivative Action"). The complaint alleges a breach of fiduciary duty, corporate waste and unjust enrichment against various officers and directors. No action has been taken to date and damages are unspecified. On March 14, 2014, this action was stayed following a ruling on the motion to dismiss in the Delaware Derivative Action. This action is in its preliminary stages and currently subject to the stay, and the Company is unable to reasonably predict an outcome or to estimate a range of reasonably possible loss.

On February 12, 2014, a derivative action was filed in the United States District Court for the Southern District of Texas, Houston Division, against the Company and certain of its officers and directors, styled Bartlinski v. Sanchez, No. 4:14-cv-00341 (S.D. Tex.) (the "Texas Federal Derivative Action"). The complaint alleges a violation of Section 14(a) of the Exchange Act and SEC Rule 14a-9. No action has been taken to date and damages are unspecified. Defendants filed a motion to dismiss on April 10, 2014. Briefing concerning the motion to dismiss concluded on May 6, 2014, but no ruling has been made at this time. This action is in its preliminary stages, and the Company is unable to reasonably predict an outcome or to reasonably estimate a range of possible loss.

Defendants believe that the allegations contained in the matters described above are without merit and intend to vigorously defend themselves against the claims raised.

In addition, in connection with the TMS transactions, the Company has committed to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we do not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we must re-assign the working interests acquired from SR. At the point that the minimum commitment is met, we will have fully paid for and earned all rights to the TMS acreage. If we desire, at our sole discretion, to continue drilling within the AMI after fulfilling the minimum well commitment, we would be required to carry SR in an additional 3 gross (1.5 net) TMS wells.

In connection with the Catarina acquisition, the 77,000 acres of undeveloped acreage that were included in the acquisition are subject to a continuous drilling obligation. Initially, such drilling obligation requires us to drill, but not complete, (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120 day period in order to maintain rights to any future undeveloped acreage. Initially, up to 30 wells drilled in excess of the minimum 50 wells in a given annual period can be carried over to satisfy part of the 50 well requirement in the subsequent annual period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

Note 16. Subsidiary Guarantors

The Company filed a registration statement on Form S-3 with the SEC, which became effective on January 14, 2013 and registered, among other securities, debt securities. The subsidiaries of the Company named therein are co-registrants with the Company, and the registration statement registered guarantees of debt securities by such subsidiaries. As of June 30, 2014, such subsidiaries are 100 percent owned by the Company and any guarantees by these subsidiaries will be full and unconditional (except for customary release provisions). In the event that more than one of these subsidiaries provide guarantees of any debt securities issued by the Company, such guarantees will constitute joint and several obligations.

The Company also filed a registration statement on Form S-4 with the SEC, which became effective on June 20, 2014, pursuant to which the Company completed an offering of debt securities which are guaranteed by its subsidiaries named therein. As of June 30, 2014, such guarantor subsidiaries are 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several.

The Company has no assets or operations independent of its subsidiaries and there are no significant restrictions upon the ability of its subsidiaries to distribute funds to the Company.

Note 17. Subsequent Events

In July 2014, the Company entered into the following three-way natural gas collar contracts that combine a long and short put with a short call:

Contract Period	Mmbtu	Short Put	Long Put	Short Call	Pricing Index
August 1, 2014 - December 31, 2015	2,590,000	$3.50	$4.00	$4.90	NYMEX NG
August 1, 2014 - December 31, 2015	2,590,000	$3.50	$4.00	$4.90	NYMEX NG

In August 2014, the Company entered into the following three-way crude oil collar contracts that combine a long and short put with a short call:

Contract Period	Barrels	Short Put	Long Put	Short Call	Pricing Index
January 1, 2015 - December 31, 2015	365,000	$75.00	$90.00	$97.00	NYMEX NG
January 1, 2015 - December 31, 2015	365,000	$75.00	$90.00	$97.25	NYMEX NG

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our condensed consolidated financial statements and related notes appearing in Part I, Item 1 of this Quarterly Report on Form 10-Q and information contained in our 2013 Annual Report. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. Please see "Cautionary Note Regarding Forward-Looking Statements."

Business Overview

Sanchez Energy Corporation, a Delaware corporation formed in August 2011, is an independent exploration and production company focused on the exploration, acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the Eagle Ford Shale in South Texas and, to a lesser extent, the TMS in Mississippi and Louisiana. We have accumulated approximately 224,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 58,000 net leasehold acres in what we believe to be the core of the TMS. We are currently focused on the horizontal development of significant resource potential from the Eagle Ford Shale, with plans to invest approximately 92% of our 2014 drilling and completion capital budget in this area. We are continuously evaluating opportunities to grow both our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on both the opportunities and the financing alternatives available to us at the time we consider such opportunities.

During 2013, we significantly expanded our proved reserves, production and undeveloped acreage through a series of acquisitions beginning with the Cotulla acquisition in the Eagle Ford Shale in South Texas, which we closed on May 31, 2013. We acquired 44,461 net acres in Dimmit, Frio, LaSalle and Zavala Counties of South Texas with 53 gross wells producing an estimated average of approximately 4,950 boe/d for the month of May 2013. The acquisition included estimated proved reserves as of March 31, 2013 of 14.2 mboe, 66% oil, 13% NGLs and 21% natural gas, with proved developed reserves estimated to account for approximately 48% of total proved reserves. We combined our new Cotulla assets with our previous Maverick area to form one operating area now known as our Cotulla area.

In July 2013, we acquired approximately 10,300 net acres and approximately 250 boe/d of estimated production in Fayette, Gonzales and Lavaca Counties, Texas for approximately $29 million. This acquisition, now known as our Five Mile Creek development within our Marquis Area, is directly to the northwest of our Prost development project.

On August 16, 2013 we completed an asset acquisition of approximately 40,000 net undeveloped acres in the TMS in Southwest Mississippi and Southeast Louisiana and the formation of an area of mutual interest and a 50/50 joint venture with our affiliate, SR. The joint venture controls approximately 115,000 gross and 80,000 net acres in what we believe to be the core of the TMS.

On October 4, 2013, we closed our Wycross acquisition in the Eagle Ford Shale. At the effective date of July 1, 2013, this acquisition added approximately 11 mboe of net proved reserves, 2,000 boe/d of production and 3,600 net contiguous acres of leasehold in McMullen County, Texas.

On June 30, 2014, we closed our Catarina acquisition in the Eagle Ford Shale with an effective date of January 1, 2014. Including the approximate $51 million deposit paid prior to closing, total consideration for the acquisition was approximately $554 million, comprised of the $639 million purchase price less approximately $85 million in normal and customary closing adjustments. The purchase price is subject to customary post-closing adjustments. Proved reserves as of the effective date were estimated to be approximately 60 mboe and were 57 mboe as of June 30, 2014 as a result of normal declines. The reserves that were produced were not replaced from the effective time to the closing date due to the substantial decrease in drilling and completion activity by the seller. Production during the time period from effective date to closing averaged approximately 22,200 boe/d.

All proved reserves are covered under lease acreage that is held by production, which acreage amounted to approximately 29,000 acres. Under the lease we have a 100% working interest and 75% net revenue interest in the lease acreage over the Eagle Ford Shale formation from the top of the Austin Chalk formation to the base of the Buda Lime formation. Each producing horizontal well that is not in an existing unit already held by production holds 320 acres by its production. The 77,000 acres of undeveloped acreage that were included in the acquisition are subject to a continuous drilling obligation. Initially, such drilling obligation requires us to drill, but not complete, (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120 day period in order to maintain rights to any future undeveloped acreage. Initially, up to 30 wells drilled in excess of the minimum 50 wells in a given annual period can be carried over to satisfy part of the 50 well requirement in the subsequent annual period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

Basis of Presentation

The condensed consolidated financial statements have been prepared in accordance with U.S. GAAP.

Our Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale, where we have assembled approximately 224,000 net leasehold acres with an average working interest of approximately 93%. Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas, approximately 60 acre well-spacing for our Marquis area, and approximately 75 acre well-spacing for our Catarina area, and assuming 80% of the acreage is drillable for Cotulla, Marquis and Catarina, and 90% of the acreage is drillable for Palmetto, we believe that there could be up to 3,000 gross (2,800 net) locations for potential future drilling. Consistent with other operators in this area, we perform multi-stage hydraulic fracturing up to 30 stages on each well depending upon the length of the lateral section. For the year 2014, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In our Marquis area, we have approximately 71,000 net operated acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We believe that our Marquis acreage lies in the volatile oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $8.5 million and $11.0 million per well based on our historical well costs. We have drilled 37 horizontal wells in our Prost area of Marquis that had average 30 day production rates of approximately 700 boe/d. We have drilled 6 horizontal wells in our Five Mile Creek area of Marquis that had average 30 day production rates of approximately 600 boe/d. We have identified up to 900 gross and net locations based on 60 acre well-spacing for potential future drilling on our Marquis acreage. For the year 2014, we plan to spend $270 - $285 million to spud 35 net wells and complete 32 net wells in our Marquis area.

In our Cotulla area, we have approximately 37,000 net acres in Dimmit, Frio, LaSalle, Zavala and McMullen Counties, Texas with an average working interest of approximately 85%. We believe that our Cotulla acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 million and $9.0 million per well based on our historical well costs. Our primary focus areas in our Cotulla area are our Alexander Ranch and Wycross development projects. In our Alexander Ranch development project, 42 wells have been brought online with average 30 day production rates of approximately 500 boe/d. In our Wycross development project, 19 wells have been brought online with average 30 day production rates of approximately 700 boe/d. We have identified up to 740 gross (700 net) locations based on 40 acre well-spacing for potential future drilling on our Cotulla area. For the year 2014, we plan to spend $190 - $210 million to spud and complete 28 net wells in our Cotulla area.

In our Palmetto area, we have approximately 9,000 net acres in Gonzales County, Texas with an average working interest of approximately 48%. We believe that our Palmetto acreage lies in the volatile oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $7.5 million and $11.0 million per well based on our historical well costs. We have participated in the drilling of 55 gross wells on our acreage that had an average 30 day production rates of approximately 900 boe/d. We have identified up to 365 gross (175 net) locations based on 40 acre well-spacing for potential future drilling in our Palmetto area. For the year 2014, we plan to spend $45 - $55 million to spud 5 and complete 8 net wells in our Palmetto area.

In our Catarina area, we have approximately 106,000 net acres in Dimmit, LaSalle and Webb Counties, Texas with a 100% working interest. For the year 2014, we plan to spend $205 - $215 million to spud 25 and complete 37 net wells in our Catarina area.

Tuscaloosa Marine Shale

In August 2013, we acquired approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS for cash and shares of our common stock plus an initial 3 gross (1.5 net) well drilling carry. In connection with the TMS transactions, we established an AMI in the TMS with SR. As part of the transaction, we acquired all of the working interests in the AMI owned at closing from three sellers (two third parties and one related party of the Company, SR), resulting in our owning an undivided 50% working interest across the AMI through the TMS formation. The AMI holds rights to approximately 115,000 gross acres and 80,000 net acres.

Total consideration for the transactions consisted of approximately $70 million in cash and the issuance of 342,760 common shares of the Company, valued at $7.5 million. The total cash consideration provided to SR, an affiliate of the Company, was $14.4 million. The acquisitions were accounted for as the purchase of assets at cost at the acquisition date.

We have also committed, as a part of the total consideration, to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we do not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we must re-assign the working interests acquired from SR. At the point that the minimum commitment is met, we will have fully paid for and earned all rights to the TMS acreage. If we desire, at our sole discretion, to continue drilling within the AMI after fulfilling the minimum well commitment, we would be required to carry SR in an additional 3 gross (1.5 net) TMS wells.

Recent well results by other operators in the area are encouraging with respect to both strong well performance and decreasing drilling and completion costs. We plan to allocate approximately 7%, or $60 - $65 million of our total 2014 capital budgets to this area. The average remaining lease term on the acreage is over 3 years, giving us ample time to allow other industry participants to further de-risk the play.

Recent Developments

In May 2014, the Company entered into exchange agreements with certain holders of the Company's Series A Preferred Stock and Series B Preferred Stock, pursuant to which such holders exchanged an aggregate of 166,025 shares of Series A Preferred Stock and 210,820 shares of Series B

Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 418,715 shares and 553,980 shares of the Company's common stock, respectively.

Outlook

As an oil and natural gas company, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well or formation decreases. Our future growth will depend on our ability to continue to add new reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through development projects associated with our current property base, improving the economics of producing oil and natural gas from our properties and selected step-out and exploratory drilling activities. In addition, we regularly review acquisition opportunities from third parties or other members of the Sanchez Group. Our ability to add estimated reserves through acquisitions and development projects is dependent on many factors, including our ability to raise capital, obtain regulatory approvals and procure contract drilling rigs and personnel. Volatility in commodity prices and sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce, the price of our common stock, and our access to capital.

Results of Operations

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013

Revenue and Production

The following table summarizes production, average sales prices and operating revenue for our oil, NGLs and natural gas operations for the periods indicated (in thousands, except average sales price and percentages):

	Three Months Ended June 30,		Increase (Decrease) 2014 vs 2013	
	2014	2013	$	%
Net Production:				
Oil (mbo)	1,356	541	815	151%
Natural gas liquids (mbbl)	262	84	178	212%
Natural gas (mmcf)	1,445	470	975	208%
Total oil equivalent (mboe)	1,859	703	1,156	164%
Average Sales Price(1):				
Oil ($ per bo)	$ 100.90	$101.42	$ (0.52)	(1)%
Natural gas liquids ($ per bbl)	$ 30.96	$ 24.48	$ 6.48	26%
Natural gas ($ per mcf)	$ 4.60	$ 4.61	$ (0.01)	0%
Oil equivalent ($ per boe)	$ 81.55	$ 84.05	$ (2.50)	(3)%
REVENUES(1):				
Oil sales	$136,902	$54,872	$82,030	149%
Natural gas liquids sales	8,116	2,047	6,069	296%
Natural gas sales	6,643	2,166	4,477	207%
Total revenues	$151,661	$59,085	$92,576	157%

(1) Excludes the impact of derivative instruments.

The following table sets forth information regarding combined net production of oil, NGLs and natural gas attributable to our properties for each of the periods presented:

	Three Months Ended June 30,	
	2014	2013
Production:		
Oil—mbo		
Marquis	482	166
Cotulla	514	114
Palmetto	359	261
Other	1	—
Total	1,356	541
Natural gas liquids—mbbl		
Marquis	55	20
Cotulla	135	15
Palmetto	72	49
Other	—	—
Total	262	84
Natural gas—mmcf		
Marquis	219	76
Cotulla	791	115
Palmetto	438	271
Other	(3)	8
Total	1,445	470
Net production volumes:		
Total oil equivalent (mboe)	1,859	703
Average daily production (boe/d)	20,437	7,726

Net Production. Production increased from 703 mboe for the three months ended June 30, 2013 to 1,859 mboe for the three months ended June 30, 2014 due to our drilling program and acquisition activity during 2013. The number of gross wells producing at the period end and the production for the periods were as follows:

	Three Months Ended June 30,			
	2014		2013	
	# Wells	mboe	# Wells	mboe
Marquis	59	575	9	198
Cotulla	114	781	68	149
Palmetto	61	503	26	355
Catarina	176	—	—	—
Other	3	—	1	1
Total	413	1,859	104	703

For the three months ended June 30, 2014, 73% of our production was oil, 14% was NGLs and 13% was natural gas compared to the three months ended June 30, 2013 production that was 77% oil, 12% NGLs and 11% natural gas.

Revenues. Oil, NGL, and natural gas sales revenues totaled $151.7 million and $59.1 million for the three months ended June 30, 2014 and 2013, respectively. Oil sales revenue for the three months ended June 30, 2014 increased $82.0 million with an increase of $82.7 million attributable to the increase in production and a decrease of $0.7 million due to the lower average sales price compared to the three months ended June 30, 2013. NGL sales revenue for the three months ended June 30, 2014 increased $6.1 million with $4.4 million attributable to the increase in production and $1.7 million due to the higher average sales price compared to the three months ended June 30, 2013. Natural gas sales revenue for the three months ended June 30, 2014 increased $4.5 million with $4.5 million attributable to the increase in production and a negligible impact of the lower average sales price compared to the three months ended June 30, 2013.

Operating Costs and Expenses

The table below presents a detail of operating costs and expenses for the periods indicated (in thousands, except percentages):

	Three Months Ended June 30,		Increase (Decrease) 2014 vs 2013	
	2014	2013	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 13,911	$ 6,813	$ 7,098	104%
Production and ad valorem taxes	7,842	3,361	4,481	133%
Depreciation, depletion, amortization and accretion	70,583	24,623	45,960	187%
General and administrative (inclusive of stock-based compensation expense of $15,943 and $4,578 for the three months ended June 30, 2014 and 2013, respectively)	28,869	12,632	16,237	129%
Total operating costs and expenses	121,205	47,429	73,776	156%
Interest and other income	3	51	(48)	(94)%
Interest expense	(17,261)	(7,069)	(10,192)	144%
Net gains (losses) on commodity derivatives	(31,900)	4,252	(36,152)	(850)%
Income tax benefit	6,544	—	6,544	*

* Not meaningful.

Oil and Natural Gas Production Expenses. Oil and natural gas production expenses are the costs incurred to produce our oil and natural gas, as well as the daily costs incurred to maintain our producing properties. Such costs also include field personnel costs, utilities, chemical additives, salt water disposal, maintenance, repairs and occasional well workover expenses related to our oil and natural gas properties. Our oil and natural gas production expenses increased 104% to $13.9 million for the three months ended June 30, 2014 as compared to $6.8 million for the same period in 2013. The increase in oil and natural gas production expenses in the second quarter of 2014 compared to the same period of 2013 is directly attributable to our increased production activities and well count in the Eagle Ford Shale, as a result of the Cotulla and Wycross acquisitions completed during 2013 and drilling activities on our existing acreage. Our average production expenses decreased from $9.69 per boe during the three months ended June 30, 2013 to $7.48 per boe for the three months ended June 30, 2014. The decrease in production expenses per boe during the period was due primarily to increased efficiency in our overall operations between the periods.

Production and Ad Valorem Taxes. Production and ad valorem taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at fixed rates established by state or local taxing authorities. Our production and ad valorem taxes totaled $7.8 million and $3.4 million for the three months ended June 30, 2014 and 2013, respectively. The increase in production and ad valorem taxes in the second quarter of 2014 compared to the same period in 2013 was due to the significant increase in revenues over the periods. Our average production and ad valorem taxes decreased from $4.78 per boe during the three months ended June 30, 2013 to $4.21 per boe for the three months ended June 30, 2014.

Depreciation, Depletion, Amortization and Accretion. Depreciation, depletion, amortization and accretion ("DD&A") reflects the systematic expensing of the capitalized costs incurred in the acquisition, exploration and development of oil and natural gas properties. We use the full-cost method of accounting and accordingly, we capitalize all costs associated with the acquisition, exploration and development of oil and natural gas properties, including unproved and unevaluated property costs. Internal costs are capitalized only to the extent they are directly related to acquisition, exploration and development activities and do not include any costs related to production, selling or general corporate administrative activities. Capitalized costs of oil and natural gas properties are amortized using the units of production method based upon production and estimates of proved oil and natural gas reserve quantities. Unproved and unevaluated property costs are excluded from the amortizable base used to determine DD&A expense. Our DD&A expense for the second quarter of 2014 increased $46.0 million to $70.6 million ($37.95 per boe) from $24.6 million ($35.03 per boe) in the second quarter of 2013. The majority of the increase in DD&A is related to the increase in depletion. The increase in depletion expense primarily resulted from a substantial increase in production during the second quarter of 2014 as compared to the same period in 2013. The increase in the depletion rate resulted from an increase in the basis of our oil and natural gas properties, including $928.8 million in future development costs for the proved undeveloped reserves, which was an increase of 8% over the June 30, 2013 estimate of $863.9 million. Estimated reserves as of June 30, 2014 were 39% higher than as of June 30, 2013. Higher production for the second quarter of 2014 as compared to the same period in 2013 resulted in a $40.4 million increase in depletion expense and the change in the depletion rate resulted in a $5.3 million increase in depletion expense. The remaining increase of $0.3 million in DD&A is related to an increase in depreciation, amortization, and accretion between the periods presented.

General and Administrative Expenses. Our general and administrative ("G&A") expenses, including stock-based compensation expense, totaled $28.9 million for the three months ended June 30, 2014 compared to $12.6 million for the same period in 2013. Excluding the stock-based compensation, G&A expenses for the three months ended June 30, 2014 and 2013 were $13.0 million and $8.0 million, respectively. This increase was due primarily to additional costs for added personnel of SOG performing services for the Company and consulting services. Our G&A expenses, excluding stock-based compensation expense, decreased from $11.46 per boe during the three months ended June 30, 2013 to $6.95 per boe for the three months ended June 30, 2014. For the three months ended June 30, 2014 and 2013, we recorded non-cash stock-based compensation expense of $15.9 million and $4.6 million, respectively. The increase in non-cash stock-based compensation expense in the second quarter of 2014 was due primarily to the increase in awards made during the year and the associated amortization recognized. Further, because the Company records stock-based compensation expense for awards granted to non-employees at fair value and the unvested awards are revalued each period, impacting the amortization over the remaining life of the awards, the Company's increase in stock price during 2014 has caused an increase to the stock-based compensation expense recognized during the quarter.

Interest Expense. For the three months ended June 30, 2014, interest expense totaled $17.3 million and included $4.4 million in amortization of debt issuance costs and write-offs of previously incurred debt issuance costs in connection with the termination of the commitment for the Bridge Facility during the period. This is compared to the three months ended June 30, 2013, for which interest expense totaled $7.1 million and included $4.4 million in amortization of debt issuance costs. The interest expense incurred during the three months ended June 30, 2014 is mainly related to the 7.75% Notes.

Commodity Derivative Transactions. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in other income and expenses. During the three months ended June 30, 2014, we recognized a net loss of $31.9 million on our commodity derivative contracts including a net loss of $5.3 million associated with the settlements of commodity derivative contracts. During the three months ended June 30, 2013, we recognized a net gain of $4.3 million on our commodity derivative contracts, including net losses of $0.3 million associated with the settlements of commodity derivative contracts and $0.4 million related to the premiums paid on derivative contracts. The increase in losses recognized during the three months ended June 30, 2014 as compared to the three months ended June 30, 2013 is a function of the increase in the number of open positions between the periods, changes in commodity prices between the periods, and the duration of the hedges.

Income Tax Expense. For the three months ended June 30, 2014, the Company recorded an income tax benefit of $6.5 million. Our effective tax rate for the three months ended June 30, 2014 was equal to the statutory rate of 35%. The Company's effective tax rate for the three months ended June 30, 2013 was 0%, due to the change in valuation allowance recorded against net deferred income tax assets.

Six Months Ended June 30, 2014 Compared to Six Months Ended June 30, 2013

Revenue and Production

The following table summarizes production, average sales prices and operating revenue for our oil, NGLs and natural gas operations for the periods indicated (in thousands, except average sales price and percentages):

	Six Months Ended June 30,		Increase (Decrease) 2014 vs 2013	
	2014	2013	$	%
Net Production:				
Oil (mbo)	2,575	818	1,757	215%
Natural gas liquids (mbbl)	514	125	389	311%
Natural gas (mmcf)	2,767	688	2,079	302%
Total oil equivalent (mboe)	3,550	1,058	2,492	236%
Average Sales Price(1):				
Oil ($ per bo)	$ 99.63	$102.94	$ (3.31)	(3)%
Natural gas liquids ($ per bbl)	$ 32.32	$ 23.78	$ 8.54	36%
Natural gas ($ per mcf)	$ 4.71	$ 4.28	$ 0.43	10%
Oil equivalent ($ per boe)	$ 80.62	$ 85.19	$ (4.57)	(5)%
REVENUES(1):				
Oil sales	$256,577	$84,199	$172,378	205%
Natural gas liquids sales	16,609	2,976	13,633	458%
Natural gas sales	13,037	2,946	10,091	343%
Total revenues	$286,223	$90,121	$196,102	218%

(1) Excludes the impact of derivative instruments.

The following table sets forth information regarding combined net production of oil, NGLs and natural gas attributable to our properties for each of the periods presented:

	Six Months Ended June 30, 2014	2013
Production:		
Oil—mbo		
Marquis	854	234
Cotulla	1,031	169
Palmetto	689	415
Other	1	—
Total	2,575	818
Natural gas liquids—mbbl		
Marquis	105	20
Cotulla	264	18
Palmetto	145	87
Other	—	—
Total	514	125
Natural gas—mmcf		
Marquis	372	115
Cotulla	1,626	115
Palmetto	767	442
Other	2	16
Total	2,767	688
Net production volumes:		
Total oil equivalent (mboe)	3,550	1,058
Average daily production (boe/d)	19,615	5,845

Net Production. Production increased from 1,058 mboe for the six months ended June 30, 2013 to 3,550 mboe for the six months ended June 30, 2014 due to our drilling program and acquisition activity during 2013. The number of gross wells producing at the period end and the production for the periods were as follows:

	Six Months Ended June 30, 2014		2013	
	# Wells	mboe	# Wells	mboe
Marquis	59	1,022	9	273
Cotulla	114	1,566	68	206
Palmetto	61	961	26	576
Catarina	176	—	—	—
Other	3	1	1	3
Total	413	3,550	104	1,058

For the six months ended June 30, 2014, 73% of our production was oil, 14% was NGLs and 13% was natural gas compared to the six months ended June 30, 2013 production that was 77% oil, 12% NGLs and 11% natural gas.

Revenues. Oil, NGLs, and natural gas sales revenues totaled $286.2 million and $90.1 million for the six months ended June 30, 2014 and 2013, respectively. Oil sales revenue for the six months ended June 30, 2014 increased $172.4 million with an increase of $180.9 million attributable to the increase in production and a decrease of $8.5 million due to the lower average sales price compared to the six months ended June 30, 2013. NGL sales revenue for the six months ended June 30, 2014 increased $13.6 million with $9.2 million attributable to the increase in production and $4.4 million due to the higher average sales price compared to the six months ended June 30, 2013. Natural gas sales revenue for the six months ended June 30, 2014 increased $10.1 million with $8.9 million attributable to the increase in production and $1.2 million due to the higher average sales price compared to the six months ended June 30, 2013.

Operating Costs and Expenses

The table below presents a detail of operating costs and expenses for the periods indicated (in thousands, except percentages):

	Six Months Ended June 30,		Increase (Decrease) 2014 vs 2013	
	2014	**2013**	**$**	**%**
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 29,823	$10,072	$ 19,751	196%
Production and ad valorem taxes	18,245	5,411	12,834	237%
Depreciation, depletion, amortization and accretion	131,834	37,996	93,838	247%
General and administrative (inclusive of stock-based compensation expense of $25,878 and $7,712, respectively, for the six months ended June 30, 2014 and 2013)	48,178	20,369	27,809	137%
Total operating costs and expenses	228,080	73,848	154,232	209%
Interest and other income	15	72	(57)	(79)%
Interest expense	(30,533)	(8,153)	(22,380)	275%
Net gains (losses) on commodity derivatives	(41,017)	624	(41,641)	*
Income tax benefit	4,679	—	4,679	*

* Not meaningful.

Oil and Natural Gas Production Expenses. Our oil and natural gas production expenses increased 196% to $29.8 million for the six months ended June 30, 2014 as compared to $10.1 million for the same period in 2013. The increase in oil and natural gas production expenses in the six months ended June 30, 2014 compared to the same period of 2013 is directly attributable to our increased production activities and well count in the Eagle Ford Shale, as a result of the Cotulla and Wycross acquisitions completed during 2013 and drilling activities on our existing acreage. Our average production expenses decreased from $9.52 per boe during the six months ended June 30, 2013 to $8.40 per boe for the six months ended June 30, 2014. The decrease in production expenses per boe during the six months ended June 30, 2014 was due primarily to increased efficiency in our overall operations compared to the same period in 2013.

Production and Ad Valorem Taxes. Our production and ad valorem taxes totaled $18.2 million and $5.4 million for the six months ended June 30, 2014 and 2013, respectively. The increase in production and ad valorem taxes in the six months ended June 30, 2014 compared to the same period in 2013 was due to the significant increase in revenues over the periods. Our average production and ad valorem taxes increased from $5.12 per boe during the six months ended June 30, 2013 to $5.13 per boe for the six months ended June 30, 2014.

Depreciation, Depletion, Amortization and Accretion. Our DD&A expense for the six months ended June 30, 2014 increased $93.8 million to $131.8 million ($37.14 per boe) from $38.0 million ($35.92 per boe) in the same period of 2013. For a discussion of our DD&A expense, see "—Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013—Costs and Operating Expenses—Depreciation, Depletion, Amortization and Accretion."

General and Administrative Expenses. Our G&A expenses, including stock-based compensation expense, totaled $48.2 million for the six months ended June 30, 2014 compared to $20.4 million for the same period in 2013. Excluding the stock-based compensation, G&A expenses for the six months ended June 30, 2014 and 2013 were $22.3 million and $12.7 million, respectively. This increase was due primarily to additional costs for added personnel of SOG performing services for the Company and consulting services. Our G&A expenses, excluding stock-based compensation expense, decreased from $11.97 per boe during the six months ended June 30, 2013 to $6.28 per boe for the six months ended June 30, 2014. For the six months ended June 30, 2014 and 2013, we recorded non-cash stock-based compensation expense of $25.9 million and $7.7 million, respectively. For a discussion of our general and administrative expenses, see "—Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 2013—Costs and Operating Expenses—General and Administrative Expenses."

Interest Expense. For the six months ended June 30, 2014, interest expense totaled $30.5 million and included $5.5 million in amortization of debt issuance costs and write-offs of previously incurred debt issuance costs in connection with the termination of the commitment for the Bridge Facility during the period. This is compared to the six months ended June 30, 2013, for which interest expense totaled $8.2 million and included $4.6 million in amortization of debt issuance costs. The interest expense incurred during the six months ended June 30, 2014 is mainly related to the 7.75% Notes.

Commodity Derivative Transactions. We apply mark to market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in other income and expenses. During the six months ended June 30, 2014, we recognized a net loss of $41.0 million on our commodity derivative contracts including a net loss of $8.0 million associated with the settlements of commodity derivative contracts. During the six months ended June 30, 2013, we recognized a net gain of $0.6 million on our commodity derivative contracts including a net loss of $0.6 million associated with the settlements of commodity derivative contracts and $0.9 million related to the premiums paid on derivative contracts. The increase in losses recognized during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013 is a function of the increase in the number of open positions between the periods, changes in commodity prices between the periods, and the duration of the hedges.

Income Tax Expense. For the six months ended June 30, 2014, the Company recorded an income tax benefit of $4.7 million. Our effective tax rate for the six months ended June 30, 2014 was 34.9% as compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is related to non-deductible general and administrative expenses recorded during the period. The Company's effective tax rate for the six months ended June 30, 2013 was 0%, due to the change in valuation allowance recorded against net deferred income tax assets.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with U.S. GAAP requires our management to select and apply accounting policies that best provide the framework to report our results of operations and financial position. The selection and application of those policies requires our management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions.

As of June 30, 2014, our critical accounting policies were consistent with those discussed in our 2013 Annual Report.

Use of Estimates

The condensed consolidated financial statements are prepared in conformity with U.S. GAAP, which requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the depletion and impairment of oil and natural gas properties, fair value accounting for acquisitions, the evaluation of unproved properties for impairment, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

Recent Accounting Pronouncements

In May 2014, the FASB issued ASU 2014-09, which supersedes nearly all existing revenue recognition guidance under U.S. GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgment and estimates may be required within the revenue recognition process than are required under existing U.S. GAAP.

The standard is effective for annual periods beginning after December 15, 2016, and interim periods therein, using either of the following transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption (which includes additional footnote disclosures). We are currently evaluating the impact of our pending adoption of ASU 2014-09 on our consolidated financial statements and have not yet determined the method by which we will adopt the standard in 2017.

Liquidity and Capital Resources

As of June 30, 2014, we had approximately $386 million in cash and cash equivalents and a $437.5 million unused borrowing base (with a $425 million elected commitment amount) under our revolving credit facility with a group of ten participating banks, resulting in available liquidity of approximately $811 million.

We expect to use our cash on hand and our internally generated cash flows from operations to fund our remaining 2014 capital expenditures.

For a description of current and previous credit agreements along with the indentures covering our Senior Notes refer to Note 6 “Long-Term Debt.”

For a description of current and previous common stock and preferred stock activity refer to Note 12 "Stockholders' Equity." In addition, in February and May 2014, the Company entered into exchange agreements with certain holders of the Company's Series A Preferred Stock and Series B Preferred Stock, pursuant to which such holders exchanged an aggregate of 1,113,515 shares of Series A Preferred Stock and 967,670 shares of Series B Preferred Stock (and waived their rights to any accrued and unpaid dividends thereon) for 2,844,289 shares and 2,575,046 shares of the Company's common stock, respectively.

As a result of these exchanges, the Company has reduced its cash dividend payments on its Series A Preferred Stock and Series B Preferred Stock during the year to date period ended June 30, 2014 by $2.7 million as compared to the amount that would have been paid based on the number of shares outstanding prior to these conversions. The Company has also reduced its anticipated future cash dividend payments by a total of approximately $1.5 million each quarter.

Cash Flows

Our cash flows for the six months ended June 30, 2014 and 2013 (in thousands) are as follows:

	Six Months Ended June 30,	
	2014	2013
Cash Flow Data:		
Net cash provided by operating activities	$ 142,035	$ 68,841
Net cash used in investing activities	$(888,118)	$(482,035)
Net cash provided by financing activities	$ 978,423	$ 589,489

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $142.0 million for the six months ended June 30, 2014 compared to $68.8 million for the same period in 2013. The increase in net cash provided by operating activities for the six months ended June 30, 2014 as compared to the same period in 2013 was related to the favorable impact of changes in working capital items, including higher sales volumes partially offset by the impact of higher average commodity prices between these periods.

One of the primary sources of variability in the Company's cash flows from operating activities is fluctuations in commodity prices, the impact of which the Company partially mitigates by entering into commodity derivatives. Sales volume changes also impact cash flow. The Company's cash flows from operating activities are also dependent on the costs related to continued operations and debt service.

Net Cash Used in Investing Activities. Net cash flows used in investing activities totaled $888.1 million for the six months ended June 30, 2014 compared to $482.0 million for the same period in 2013. Capital expenditures for leasehold and drilling activities for the six months ended June 30, 2014 totaled $328.7 million, primarily associated with bringing online 49 gross wells. We paid cash of $553.5 million for the oil and natural gas properties acquired in the Catarina acquisition. We received cash of $0.7 million and $0.5 million as final settlement for the oil and natural gas properties acquired in the Cotulla acquisition and the Wycross acquisition, respectively. In addition, we invested $7.1 million in other property and equipment. For the six months ended June 30, 2013, we incurred capital expenditures of $175.2 million, primarily associated with the drilling and completing of 21 gross wells. We paid cash of $291.9 million for the oil and natural gas properties acquired in the Cotulla acquisition and other immaterial acquisitions of oil and natural gas properties. We paid cash of approximately $25 million to purchase held-to-maturity investments. In addition, we invested $1.5 million in computer and other equipment. Partially offsetting these costs were proceeds of $11.6 million from the sale of marketable securities.

Net Cash Provided by Financing Activities. Net cash flows provided by financing activities totaled $978.4 million for the six months ended June 30, 2014 compared to $589.5 million for the same period in 2013. During the six months ended June 30, 2014, we received net proceeds from the issuance of common stock of $167.6 million, after deducting offering costs payable by us of $8.7 million. We also made payments of $8.3 million for dividends on our Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock. We received net proceeds of approximately $829 million from the issuance of our 6.125% Notes, consisting of gross proceeds of $850 million and debt issuance costs of $20.9 million. Other debt issuance costs for the six months ended June 30, 2014 totaled $10.0 million. On May 12, 2014, the Company borrowed $100 million under the First Lien Credit Agreement. The Company used proceeds from the issuance of the 6.125% Notes to repay the $100 million outstanding under the First Lien Credit Agreement, in addition to funding a portion of the purchase price of the Catarina acquisition.

During the six months ended June 30, 2013, we received net proceeds from the private placement of preferred stock of $216.6 million, after deducting placement agent's fees and offering costs payable by us of $8.4 million. We also received net proceeds of approximately $388 million from the private placement of our Original Notes, consisting of gross proceeds of $400 million and debt issuance costs of $11.8 million included in the $18.5 million discussed below. During the first quarter of 2013, we borrowed $50 million under our Second Lien Term Credit Agreement (the "Second Lien Credit Agreement"). On May 30, 2013, we borrowed $90 million under our Previous First Lien Credit Agreement. On May 31, 2013, we borrowed $96 million under our First Lien Credit Agreement, and used the proceeds to repay the $90 million borrowed under our Previous First Lien Credit Agreement. The outstanding borrowings under our First Lien Credit Agreement and Second Lien Term Credit Agreement were repaid during the second quarter of 2013 with proceeds from the Original Notes offering. Other financing costs for the six months ended June 30, 2013 included $18.5 million for debt issuance costs, $7.6 million paid for preferred dividends and $1.0 million paid for the purchase of common stock to settle taxes on the vesting of employee stock grants.

Off-Balance Sheet Arrangements

As of June 30, 2014, we did not have any off-balance sheet arrangements.

Commitments and Contractual Obligations

Refer to Note 15 "Commitments and Contingencies" for a description of lawsuits pending against the Company.

As of June 30, 2014, our contractual obligations included our Senior Notes, interest expense on our Senior Notes, deferred premiums on our commodity hedging contracts, asset retirement obligations and rent expense for our corporate offices. During the three months ended June 30, 2014, the

Company entered into a lease for a new corporate office location beginning in the fourth quarter of 2014. The following table summarizes our contractual obligations as of June 30, 2014 (in thousands):

	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Notes	$ —	$ —	$ —	$1,450,000	$1,450,000
Interest expense(1)	75,134	197,125	197,125	301,250	770,634
Derivative liabilities(2)	3,143	2,465	—	—	5,608
Asset retirement obligations(3)	—	—	—	22,626	22,626
Office rent(4)	1,028	6,527	6,858	21,737	36,150
Total	$79,305	$206,117	$203,983	$1,795,613	$2,285,018

(1) Represents estimated interest payments that will be due under the 7.75% Notes and 6.125% Notes that will mature on June 15, 2021 and January 15, 2023, respectively.

(2) Represents payments due for deferred premiums on our commodity hedging contracts. See *Note 7—Derivative Instruments* in the *Notes to the Condensed Consolidated Financial Statements* under Item 1 of this Form 10-Q.

(3) Amounts represent the present value of our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See *Note 9—Asset Retirement Obligations* in the *Notes to the Condensed Consolidated Financial Statements* under Item 1 of this Form 10-Q.

(4) Represents payments due for leasing corporate office space in Houston, Texas. Lease will begin on November 1, 2014 and continue until March 31, 2025.

In addition, in connection with the TMS transactions, the Company has committed to carry SR for its 50% working interest in an initial 3 gross (1.5 net) TMS wells to be drilled within the AMI. In the event that we do not fulfill in a timely manner our obligations with regard to the initial TMS well commitment we must re-assign the working interests acquired from SR. At the point that the minimum commitment is met, we will have fully paid for and earned all rights to the TMS acreage. If we desire, at our sole discretion, to continue drilling within the AMI after fulfilling the minimum well commitment, we would be required to carry SR in an additional 3 gross (1.5 net) TMS wells.

In connection with the Catarina acquisition, the 77,000 acres of undeveloped acreage that were included in the acquisition are subject to a continuous drilling obligation. Initially, such drilling obligation requires us to drill, but not complete, (i) 50 wells in each annual period commencing on July 1, 2014 and (ii) at least one well in any consecutive 120 day period in order to maintain rights to any future undeveloped acreage. Initially, up to 30 wells drilled in excess of the minimum 50 wells in a given annual period can be carried over to satisfy part of the 50 well requirement in the subsequent annual period on a well for well basis. The lease also created a customary security interest in the production therefrom in order to secure royalty payments to the lessor and other lease obligations. Our current capital budget and plans include the drilling of at least the minimum number of wells required to maintain access to such undeveloped acreage.

Non-GAAP Financial Measures

Adjusted EBITDA

We present adjusted EBITDA attributable to common stockholders ("Adjusted EBITDA") in addition to our reported net income (loss) in accordance with U.S. GAAP. Adjusted EBITDA is a non-GAAP financial measure that is used as a supplemental financial measure by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. It is also used to assess our ability to incur and service debt and fund capital expenditures. We define Adjusted EBITDA as net income (loss):

Plus:

- Interest expense, including net losses (gains) on interest rate derivative contracts;
- Net losses (gains) on commodity derivative contracts;
- Net settlements on commodity derivative contracts;
- Premiums (paid) on commodity derivative contracts;
- Depreciation, depletion, amortization and accretion;
- Stock-based compensation expense;
- Acquisition costs included in general and administrative;
- Income tax expense (benefit);
- Loss (gain) on sale of oil and natural gas properties;
- Impairment of oil and natural gas properties; and
- Other non-recurring items that we deem appropriate.

Less:

- Interest income; and
- Other non-recurring items that we deem appropriate.

Our Adjusted EBITDA should not be considered an alternative to net income (loss), operating income (loss), cash flows provided by or used in operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

The following table presents a reconciliation of our net income (loss) to Adjusted EBITDA (in thousands, except per share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$(12,158)	$ 8,890	$ (8,713)	$ 8,816
Plus:				
Interest expense	17,261	7,069	30,533	8,153
Net losses (gains) on commodity derivative contracts	31,900	(4,252)	41,017	(624)
Net settlements on commodity derivative contracts	(5,337)	(260)	(8,017)	(556)
Premiums paid on commodity derivative contracts	—	(455)	—	(905)
Depreciation, depletion, amortization and accretion	70,583	24,623	131,834	37,996
Stock-based compensation	15,943	4,578	25,878	7,712
Acquisition costs included in general and administrative	890	3,069	890	3,685
Income tax benefit	(6,544)	—	(4,679)	—
Less:				
Interest income	(3)	(51)	(15)	(72)
Adjusted EBITDA	$112,535	$43,211	$208,728	$64,205

The following table presents a reconciliation of net cash provided by operating activities to Adjusted EBITDA (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net cash provided by operating activities	$ 77,452	$28,995	$142,035	$ 68,841
Net change in operating assets and liabilities	22,620	9,131	43,202	(10,389)
Interest expense, net	12,659	2,660	24,561	3,481
Settlements on commodity derivative contracts, non-cash	(1,086)	(644)	(1,960)	(1,413)
Acquisition costs included in general & administrative	890	3,069	890	3,685
Adjusted EBITDA	$112,535	$43,211	$208,728	$ 64,205

Adjusted Net Income

We present adjusted net income attributable to common stockholders (“Adjusted Net Income”) in addition to our reported net income (loss) in accordance with U.S. GAAP. This information is provided because management believes exclusion of the impact of our unrealized gains and losses on derivatives not accounted for as cash flow hedges, stock-based compensation expense and non-recurring items will help investors compare results between periods, identify operating trends that could otherwise be masked by these items and highlight the impact that commodity price volatility has on our results. We define Adjusted Net Income as net income (loss):

Plus:

- Non-cash preferred stock dividends associated with conversion;
- Net losses (gains) on commodity derivative contracts;
- Net settlements on commodity derivative contracts;
- Premiums (paid) on commodity derivative contracts;
- Stock-based compensation expense;
- Acquisition costs included in general and administrative;
- Other non-recurring items that we deem appropriate; and
- Tax impact of adjustments to net income (loss).

Less:

- Preferred stock dividends; and
- Other non-recurring items that we deem appropriate.

The following table presents a reconciliation of our net income (loss) to Adjusted Net Income (in thousands, except per share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net income (loss)	$(12,158)	$ 8,890	$ (8,713)	$ 8,816
Less: Preferred stock dividends	(7,132)	(5,484)	(25,325)	(7,556)
Net income (loss) attributable to common shares	(19,290)	3,406	(34,038)	1,260
Plus:				
Non-cash preferred stock dividends associated with conversion	3,112	—	17,013	—
Net losses (gains) on commodity derivative contracts	31,900	(4,252)	41,017	(624)
Net settlements on commodity derivative contracts	(5,337)	(260)	(8,017)	(556)
Premiums paid on commodity derivative contracts	—	(455)	—	(905)
Stock-based compensation	15,943	4,578	25,878	7,712
Acquisition costs included in general and administrative	890	3,069	890	3,685
Tax impact(3)	(15,131)	—	(20,883)	—
Adjusted net income	12,087	6,086	21,860	10,572
Adjusted net income allocable to participating securities	(558)	(284)	(1,008)	(467)
Adjusted net income attributable to common stockholders	$ 11,529	$ 5,802	$ 20,852	$10,105
Adjusted net income per common share—basic and diluted(1)(2)	$ 0.23	$ 0.17	$ 0.43	$ 0.30
Weighted average number of unrestricted outstanding common shares used to calculate adjusted net income per common share—basic and dilutive(1)(2)	50,602	33,117	48,825	33,108

(1) The three and six months ended June 30, 2014 excludes 423,771 and 829,375 shares of weighted average restricted stock and 13,253,510 and 14,502,257 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted adjusted net income per common share as these shares were anti-dilutive.

(2) The three and six months ended June 30, 2013 excludes 208,130 and 539,141 shares of weighted average restricted stock and 17,491,500 and 12,466,950 shares of common stock resulting from an assumed conversion of the Company's Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock from the calculation of the denominator for diluted adjusted net income per common share as these shares were anti-dilutive.

(3) The tax impact is computed by utilizing the Company's effective tax rate on the adjustments to reconcile net income to adjusted net income but excludes non-cash preferred stock dividends associated with conversion.

Adjusted Net Income is not intended to represent cash flows for the period, nor is it presented as a substitute for net income (loss), operating income (loss), cash flows provided by or used in operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and, potentially, interest rates as described below.

The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, NGLs and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, NGL and natural gas production. Realized pricing is primarily driven by the prevailing market prices applicable to our natural gas and oil production. Pricing for oil, NGL and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. The prices we receive for our oil, NGL and natural gas production depend on many factors outside of our control, such as the strength of the global economy.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or, through options, modify the future prices realized. These transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. In addition, we enter into option transactions, such as puts or put spreads, as a way to manage our exposure to fluctuating prices. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. We do not enter into derivative contracts for speculative trading purposes.

As of June 30, 2014, we had the following crude oil swaps, collars, and put spreads covering anticipated future production:

Contract Period	Derivative Instrument	Barrels	Purchased	Sold	Pricing Index
July 1, 2014 - December 31, 2014	Swap	138,000	$92.00	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	138,000	$91.35	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	138,000	$92.45	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	184,000	$95.45	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Swap	184,000	$93.25	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$89.65	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$90.05	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$88.48	n/a	NYMEX WTI
January 1, 2015 - December 31, 2015	Swap	365,000	$88.35	n/a	NYMEX WTI
July 1, 2014 - December 31, 2014	Collar	184,000	$90.00	$99.10	NYMEX WTI
July 1, 2014 - December 31, 2014	Put Spread	184,000	$90.00	$75.00	NYMEX WTI

As of June 30, 2014, we had the following crude oil enhanced swaps covering anticipated future production:

Contract Period	Barrels	Purchased	Put	Pricing Index
January 1, 2015 - December 31, 2015	365,000	$91.46	$75.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$93.13	$75.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$92.20	$75.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$91.46	$75.00	NYMEX WTI

As of June 30, 2014, we had the following natural gas swaps and collars covering anticipated future production:

Contract Period	Derivative Instrument	Mmbtu	Purchased	Sold	Pricing Index
July 1, 2014 - December 31, 2014	Swap	368,000	$4.23	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Swap	368,000	$4.23	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Swap	368,000	$4.24	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Swap	368,000	$4.61	n/a	NYMEX NG
July 1, 2014 - December 31, 2014	Collar	368,000	$4.00	$4.50	NYMEX NG

As of June 30, 2014, we had the following natural gas enhanced swaps covering anticipated future production:

Contract Period	Mmbtu	Purchased	Put	Pricing Index
January 1, 2015 - December 31, 2015	2,190,000	$4.44	$3.75	NYMEX NG
January 1, 2015 - December 31, 2015	1,095,000	$4.40	$3.75	NYMEX NG
January 1, 2015 - December 31, 2015	730,000	$4.50	$3.75	NYMEX NG

As of June 30, 2014, we had the following three-way collar crude oil contracts that combine a long and short put with a short call:

Contract Period	Barrels	Short Put	Long Put	Short Call	Pricing Index
July 1, 2014 - December 31, 2014	276,000	$65.00	$85.00	$102.25	NYMEX WTI
July 1, 2014 - December 31, 2014	184,000	$75.00	$95.00	$107.50	LLS
July 1, 2014 - December 31, 2014	184,000	$75.00	$90.00	$ 96.22	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$70.00	$85.00	$ 95.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$70.00	$85.00	$ 95.00	NYMEX WTI
January 1, 2015 - December 31, 2015	365,000	$70.00	$85.00	$ 94.75	NYMEX WTI

As of June 30, 2014, the fair value of our commodity derivative contracts was a net liability of $36.4 million, including a deferred premium liability of $5.6 million, of which $3.1 million settles during the next twelve months. A 10% increase in the oil index price above the June 30, 2014 price would result in a decrease in the fair value of our commodity derivative contracts of $90.2 million; conversely, a 10% decrease in the oil index price would result in an increase of $11.8 million.

Interest Rate Risk

As of June 30, 2014, no amounts were outstanding under our First Lien Credit Agreement. Our 7.75% Notes bear a fixed interest rate of 7.75% with an expected maturity date of June 15, 2021, and we had $600 million outstanding as of June 30, 2014. Our 6.125% Notes bear a fixed interest rate of 6.125% with an expected maturity date of January 15, 2023, and we had $850 million outstanding as of June 30, 2014. We currently do not have any interest rate derivative contracts in place. If we incur significant debt with a risk of fluctuating interest rates in the future, we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report pursuant to Rule 13a-15 promulgated pursuant to the Exchange Act. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to provide reasonable assurance that material information required to be disclosed by us in reports that we file or submit under the Exchange Act is appropriately recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that information required to be disclosed by us in the reports we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Controls

There was no change in our internal control over financial reporting during the three months ended June 30, 2014 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a description of our material pending legal proceedings, please refer to Note 15 "Commitments and Contingencies."

Item 1A. Risk Factors

Consider carefully the risk factors under the caption "Risk Factors" under Part I, Item 1A in our 2013 Annual Report, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2013 Annual Report; and in our other public filings, press releases, and public discussions with our management.

The Catarina acquisition involves risks associated with acquisitions and integrating acquired assets, including the potential exposure to significant liabilities, and the intended benefits of the Catarina acquisition may not be realized.

The Catarina acquisition involves risks associated with acquisitions and integrating acquired assets into existing operations, including that:

- our senior management's attention may be diverted from the management of daily operations to the integration of the assets acquired in the Catarina acquisition;
- we could incur significant unknown and contingent liabilities for which we have limited or no contractual remedies or insurance coverage;
- the assets acquired in the Catarina acquisition may not perform as well as we anticipate; and
- unexpected costs, delays and challenges may arise in integrating the assets acquired in the Catarina acquisition into our existing operations.

Even if we successfully integrate the assets acquired in the Catarina acquisition into our operations, it may not be possible to realize the full benefits we anticipate or we may not realize these benefits within the expected timeframe. If we fail to realize the benefits we anticipate from the Catarina acquisition, our business, results of operations and financial condition may be adversely affected.

Under the terms of the lease with respect to the Catarina assets, we are subject to annual drilling and development requirements and failure to comply with these requirements may result in loss of our interests in the Catarina area that are not held by production.

In order to protect our exploration and development rights in the Catarina area, we are required to meet certain drilling and other requirements under the lease with respect to this area (the "Lease"). For example, the Lease currently requires us to drill 50 wells per year (measured from July to July). If we fail to meet the minimum drilling commitment under the terms of the Lease, we would forfeit our acreage under the Lease and rights to develop land not held by production (excluding, in certain instances, associated rights such as midstream assets). In addition, the Lease requires us to go no longer than 120 days without spudding a well, and, under the terms of the Lease, failure to do so would result in the forfeiture of our acreage under the Lease and rights to develop land not held by production (excluding, in certain instances, acreage upon which associated midstream assets are located). Our drilling plans for our undeveloped leasehold acreage are subject to change based upon various factors, including factors that are beyond our control, such as drilling results, oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals. Because of these uncertainties, we cannot assure you that we will be able meet our obligations under the Lease. If the Lease expires, we will lose our right to develop the related properties on this acreage, which could adversely affect our business, financial condition and results of operations.

The geographic concentration of the properties in the Catarina area of approximately 106,000 contiguous net acres under one lease subjects us to an increased risk of loss of revenue or curtailment of production from factors specifically affecting the Catarina acreage.

The Catarina assets, comprised of approximately 106,000 contiguous net acres in Dimmit, LaSalle and Webb Counties, Texas under the Lease, represent, on a pro forma basis, approximately 49% of our proved reserves as of June 30, 2014, approximately 34% of our production for the six months ended June 30, 2014, and approximately 47% of our Eagle Ford acreage as of June 30, 2014. Some or all of the Catarina properties could be affected should the region experience severe weather or natural disasters, moratoria on drilling or permitting delays, delays in or the inability to obtain regulatory approvals, delays or decreases in production, delays or decreases in the availability of drilling rigs and related equipment, facilities, personnel or services, delays or decreases in the availability of capacity to transport, gather or process production, and/or changes in the regulatory, political and fiscal environment. We maintain insurance coverage for only a portion of risks that may affect our business. In addition, we may lose certain of our rights under the Lease under certain circumstances. Under the terms of the Lease, we will be subject to annual drilling and development requirements and failure to comply with these requirements would result in loss of our interests in the Catarina area that are not held by production. Due to the concentrated nature of our portfolio of properties, particularly with respect to the Catarina area, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

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

Repurchase of Equity Securities

Period	Total number of shares withheld(1)	Average price per share	Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
April 1, 2014 - April 30, 2014	1,466	$29.75	—	—
May 1, 2014 - May 31, 2014	—	$ —	—	—
June 1, 2014 - June 30, 2014	—	$ —	—	—

(1) Represents shares that were withheld by us to satisfy employee tax withholding obligations that arose upon the lapse of restrictions on restricted stock.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Item 6. Exhibits

EXHIBIT INDEX

Each exhibit identified below is filed or furnished as part of this report.

2.1	Purchase and Sale Agreement by and between SWEPI LP and Shell Gulf of Mexico Inc., as Sellers, and Sanchez Energy Corporation, as Buyer, dated May 21, 2014, effective as of January 1, 2014 (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on May 22, 2014, and incorporated herein by reference).*
3.1	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Sanchez Energy Corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on May 28, 2013, and incorporated herein by reference).
3.2	Restated Certificate of Incorporation of Sanchez Energy Corporation, effective as of May 28, 2013 (filed as Exhibit 3.2 to the Company's Quarterly Report on Form 10-Q on November 8, 2013 and incorporated herein by reference).
3.3	Amended and Restated Bylaws, dated as of December 13, 2011 (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K on December 19, 2011, and incorporated herein by reference).
4.1	Second Supplemental Indenture, dated as of June 2, 2014, by and among Sanchez Energy Corporation, SN Catarina, LLC, the existing guarantors and U.S. Bank National Association as trustee (filed as Exhibit 4.6 to the Company's Registration Statement on Form S-4 on June 11, 2014, and incorporated herein by reference).
4.2	Indenture, dated as of June 27, 2014, among Sanchez Energy Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference).
4.3	Registration Rights Agreement, dated as of June 27, 2014, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and RBC Capital Markets, LLC, as representative of the several initial purchasers named therein (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference).
10.1	Purchase Agreement, dated June 13, 2014, by and among Sanchez Energy Corporation, the subsidiary guarantors named therein and RBC Capital Markets, LLC and Credit Suisse Securities (USA), LLC, as representatives of the several initial purchasers named therein (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 16, 2014, and incorporated herein by reference).
10.2	Second Amended and Restated Credit Agreement, dated as of June 30, 2014, among Sanchez Energy Corporation, as borrower, SEP Holdings III, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC, as loan parties, Royal Bank of Canada, as administrative agent, Capital One, National Association, as syndication agent, Compass Bank and SunTrust Bank as co-documentation agents, RBC Capital Markets as sole lead arranger and sole book runner, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on July 2, 2014, and incorporated herein by reference).

31.1(a)		Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)		Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)		Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)		Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS(b)	—	XBRL Instance Document.
101.SCH(b)	—	XBRL Taxonomy Extension Schema Document.
101.CAL(b)	—	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF(b)	—	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB(b)	—	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE(b)	—	XBRL Taxonomy Extension Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

* The exhibits and schedules to this agreement have been omitted from this filing pursuant to Item 601(b)(2) of Regulation S-K. The Company will furnish copies of such omitted exhibits and schedules to the SEC upon request. Descriptions of such exhibits and schedules are on pages iv and v of the Purchase and Sale Agreement.

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, on August 11, 2014.

SANCHEZ ENERGY CORPORATION

By: /s/ MICHAEL G. LONG

Michael G. Long
Executive Vice President and Chief Financial Officer