Sanchez Energy Corp
Form 10-Q
November 09, 2015
Table of Contents

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 September 30, 2015

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	45 3090102
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
1000 Main Street, Suite 3000	
Houston, Texas	77002
(Address of principal executive offices)	(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 November 6, 2015: 61,914,572.

Table of Contents

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,” “strateg 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 timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids (“NGLs”), natural gas and related commodities;

- 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;

- our ability to compete with other companies in the oil and natural gas industry;

Table of Contents

- 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, the actions of the Organization of Petroleum Exporting Countries and other factors affecting the supply of oil and natural gas;

- 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.

Table of Contents

Sanchez Energy Corporation

Form 10 Q

For the Quarterly Period Ended September 30, 2015

Table of Contents

Table of Contents

PART I—FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

Sanchez Energy Corporation

Condensed Consolidated Balance Sheets (Unaudited)

(in thousands, except share amounts)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$ 196,884	$ 473,714
Oil and natural gas receivables	34,686	69,795
Joint interest billings receivables	1,662	14,676
Accounts receivable - related entities	3,790	386
Fair value of derivative instruments	131,991	100,181
Other current assets	19,210	23,002
Total current assets	388,223	681,754
Oil and natural gas properties, at cost, using the full cost method:		
Unproved oil and natural gas properties	322,149	385,827
Proved oil and natural gas properties	3,052,929	2,582,441
Total oil and natural gas properties	3,375,078	2,968,268
Less: Accumulated depreciation, depletion, amortization and impairment	(2,365,396)	(706,590)
Total oil and natural gas properties, net	1,009,682	2,261,678
Other assets:		
Debt issuance costs, net	43,256	48,168
Fair value of derivative instruments	30,442	24,024
Deferred tax asset	39,840	40,685
Investments	1,136	—
Other assets	19,641	19,101
Total assets	$ 1,532,220	$ 3,075,410
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 16,542	$ 29,487

Other payables	3,458	4,415
Accrued liabilities:		
Capital expenditures	72,094	162,726
Other	65,981	67,162
Deferred premium liability	18,377	—
Deferred tax liability	39,840	33,242
Other current liabilities	—	5,166
Total current liabilities	216,292	302,198
Long term debt, net of premium and discount	1,746,807	1,746,263
Asset retirement obligations	34,559	25,694
Deferred premium liability	6,170	—
Fair value of derivative instruments	—	889
Other liabilities	1,969	779
Total liabilities	2,005,797	2,075,823
Commitments and contingencies (Note 16)		
Stockholders' equity:		
Preferred stock ($0.01 par value, 15,000,000 shares authorized; 1,838,985 shares issued and outstanding as of September 30, 2015 and December 31, 2014 of 4.875% Convertible Perpetual Preferred Stock, Series A; 3,532,330 shares issued and outstanding as of September 30, 2015 and December 31, 2014 of 6.500% Convertible Perpetual Preferred Stock, Series B)	53	53
Common stock ($0.01 par value, 150,000,000 shares authorized; 61,885,306 and 58,580,870 shares issued and outstanding as of September 30, 2015 and December 31, 2014, respectively)	619	586
Additional paid-in capital	1,080,558	1,064,667
Accumulated deficit	(1,554,807)	(65,719)
Total stockholders' equity (deficit)	(473,577)	999,587
Total liabilities and stockholders' equity	$ 1,532,220	$ 3,075,410

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

Table of Contents

Sanchez Energy Corporation

Condensed Consolidated Statements of Operations (Unaudited)

(in thousands, except per share amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
REVENUES:				
Oil sales	$ 69,532	$ 157,907	$ 244,554	$ 414,484
Natural gas liquid sales	17,055	27,309	48,602	43,918
Natural gas sales	27,939	22,134	73,091	35,171
Total revenues	114,526	207,350	366,247	493,573
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	40,345	34,380	110,166	64,203
Production and ad valorem taxes	3,038	10,916	20,011	29,161
Depreciation, depletion, amortization and accretion	89,167	93,463	296,541	225,297
Impairment of oil and natural gas properties	454,628	—	1,365,000	—
General and administrative (inclusive of stock-based compensation expense of $355 and $10, respectively, for the three months ended September 30, 2015 and 2014, and $15,924 and $25,888, respectively, for the nine months ended September 30, 2015 and 2014)	15,851	12,821	59,290	60,999
Total operating costs and expenses	603,029	151,580	1,851,008	379,660
Operating income (loss)	(488,503)	55,770	(1,484,761)	113,913
Other income (expense):				
Interest income and other income (expense)	(753)	82	(1,804)	97
Interest expense	(31,442)	(27,612)	(94,500)	(58,145)
Net gains on commodity derivatives	103,996	47,416	111,550	6,399
Total other income (expense)	71,801	19,886	15,246	(51,649)
Income (loss) before income taxes	(416,702)	75,656	(1,469,515)	62,264
Income tax expense	158	26,625	7,600	21,946
Net income (loss)	(416,860)	49,031	(1,477,115)	40,318
Less:				
Preferred stock dividends	(3,991)	(4,274)	(11,973)	(29,599)
Net income allocable to participating securities	—	(2,068)	—	(495)
Net income (loss) attributable to common stockholders	$ (420,851)	$ 42,689	$ (1,489,088)	$ 10,224
Net income (loss) per common share - basic	$ (7.33)	$ 0.77	$ (26.06)	$ 0.20
	57,426	55,732	57,141	51,153

Weighted average number of shares used to calculate net income (loss) attributable to common stockholders - basic				
Net income (loss) per common share - diluted	$ (7.33)	$ 0.69	$ (26.06)	$ 0.20
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders - diluted	57,426	68,340	57,141	51,153

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

Table of Contents

Sanchez Energy Corporation

Condensed Consolidated Statement of Stockholders' Equity for the Nine Months Ended September 30, 2015 (Unaudited)

(in thousands)

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-in	Accumulated	Total Stockholders' Equity
	Shares	Amount	Shares	Amount	Shares	Amount	Capital	Deficit	(Deficit)
BALANCE, December 31, 2014	1,839	$ 18	3,532	$ 35	58,581	$ 586	$ 1,064,667	$ (65,719)	$ 999,587
Preferred stock dividends	—	—	—	—	—	—	—	(11,973)	(11,973)
Restricted stock awards, net of forfeitures	—	—	—	—	3,304	33	(33)	—	—
Stock-based compensation	—	—	—	—	—	—	15,924	—	15,924
Net loss	—	—	—	—	—	—	—	(1,477,115)	(1,477,115)
BALANCE, September 30, 2015	1,839	$ 18	3,532	$ 35	61,885	$ 619	$ 1,080,558	$ (1,554,807)	$ (473,577)

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

Table of Contents

Sanchez Energy Corporation

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Nine Months Ended September 30, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (1,477,115)	$ 40,318
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	296,541	225,297
Impairment of oil and natural gas properties	1,365,000	—
Stock-based compensation expense	15,924	25,888
Net gains on commodity derivative contracts	(111,550)	(6,399)
Net cash settlement received (paid) on commodity derivative contracts	89,558	(9,652)
Cash reimbursements received for operating leasehold improvements	2,650	—
Premiums paid on commodity derivative contracts	(121)	(241)
Loss on investment in SPP	864	—
Amortization of debt issuance costs	5,312	7,215
Accretion of debt discount, net	544	654
Deferred taxes	7,443	21,946
Changes in operating assets and liabilities:		
Accounts receivable	52,138	(52,957)
Other current assets	3,792	(10,734)
Accounts payable	(12,945)	(29,594)
Accounts receivable - related entities	(3,404)	257
Other payables	(836)	1,818
Accrued liabilities	(1,181)	58,864
Other current liabilities	(5,166)	—
Other liabilities	1,190	—
Net cash provided by operating activities	228,638	272,680
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments for oil and natural gas properties	(562,599)	(532,300)
Payments for other property and equipment	(4,572)	(9,581)
Proceeds from sale of oil and natural gas properties	81,734	—
Acquisition of oil and natural gas properties	(7,658)	(558,113)

Net cash used in investing activities	(493,095)	(1,099,994)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	—	100,000
Repayment of borrowings	—	(100,000)
Issuance of senior notes, net of premium and discount	—	1,152,250
Issuance of common stock	—	176,250
Payments for offering costs	—	(8,731)
Financing costs	(400)	(37,412)
Preferred dividends paid	(11,973)	(12,302)
Net cash provided by (used in) financing activities	(12,373)	1,270,055
Increase (decrease) in cash and cash equivalents	(276,830)	442,741
Cash and cash equivalents, beginning of period	473,714	153,531
Cash and cash equivalents, end of period	$ 196,884	$ 596,272
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Asset retirement obligations	$ 7,451	$ 19,236
Change in accrued capital expenditures	(90,632)	34,789
Common stock issued in exchange for preferred stock	—	123,731
SUPPLEMENTAL DISCLOSURE:		
Cash paid for interest	$ 98,104	$ 24,527

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

Table of Contents

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, 2014 from the audited financial statements filed in its Annual Report on Form 10-K for the fiscal year ended December 31, 2014 (the "2014 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 2014 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 September 30, 2015, the Company’s significant accounting policies are consistent with those discussed in Note 2, “Basis of Presentation and Summary of Significant Accounting Policies,” in the notes to the Company’s consolidated financial statements contained in its 2014 Annual Report.

Principles of Consolidation

The Company’s condensed consolidated financial statements include the accounts of the Company and its subsidiaries. All intercompany balances and transactions have been eliminated.

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, 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 July 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2015-11, “Simplifying the Measurement of Inventory,” effective for annual and interim periods beginning

Table of Contents

after December 15, 2016. ASU 2015-11 changes the inventory measurement principle for entities using the first-in, first out (FIFO) or average cost methods. For entities utilizing one of these methods, the inventory measurement principle will change from lower of cost or market to the lower of cost and net realizable value. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

In April 2015, the FASB issued ASU 2015-03, "Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs." This guidance is intended to more closely align the presentation of debt issuance costs under U.S. GAAP with the presentation requirements under the International Financial Reporting Standards. Under this new standard, debt issuance costs related to a recognized debt liability will be presented on the balance sheet as a direct deduction from the debt liability, similar to the presentation of debt discounts, rather than as a separate asset as previously presented. This guidance is effective for fiscal years and interim periods beginning after December 15, 2015. The guidance is to be applied retrospectively to each prior period presented. Early adoption is permitted. The effects of this accounting standard on our financial position, results of operations and cash flows are not expected to be material.

In February 2015, the FASB issued ASU 2015-02, "Consolidation—Amendments to the Consolidation Analysis." This ASU will simplify existing requirements by reducing the number of acceptable consolidation models and placing more emphasis on risk of loss when determining a controlling financial interest. The provisions of this new standard will affect how limited partnerships and similar entities are assessed for consolidation, including the elimination of the presumption that a general partner should consolidate a limited partnership. This ASU is effective for annual and interim periods beginning in 2016 and is required to be adopted using a retrospective or modified retrospective approach, with early adoption permitted. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)." This guidance outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods and services. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. Early adoption is not permitted. The guidance may be applied retrospectively to each prior period presented or retrospectively with the cumulative effect recognized as of the date of initial application. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements, but do not expect the impact to be material.

Note 3. Acquisitions and Divestitures

Our acquisitions are accounted for under the acquisition method of accounting in accordance with Accounting Standards Codification ("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 contiguous acreage in Dimmit, LaSalle and Webb Counties, Texas with 176 gross producing wells (the "Catarina acquisition") for an aggregate adjusted purchase price of $557.1 million. The effective date of the transaction was January 1, 2014. The purchase price was funded with a portion of the proceeds from the issuance of the $850 million senior unsecured 6.125% notes due 2023 (the "Original 6.125%

Table of Contents

Notes") 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	$ 446,906
Unproved properties	122,224
Other assets acquired	2,682
Fair value of assets acquired	571,812
Asset retirement obligations	(14,723)
Fair value of net assets acquired	$ 557,089

Palmetto Disposition

On March 31, 2015, we completed our disposition to a subsidiary of Sanchez Production Partners LP ("SPP") of escalating amounts of partial working interests in 59 wellbores located in Gonzales County, Texas (the "Palmetto disposition") for an adjusted purchase price of approximately $83.4 million. The effective date of the transaction was January 1, 2015. The aggregate average working interest percentage initially conveyed was 18.25% per wellbore and, upon January 1 of each subsequent year after the closing, the purchaser's working interest will automatically increase in incremental amounts according to the purchase agreement until January 1, 2019, at which point the purchaser will own a 47.5% working interest and we will own a 2.5% working interest in each of the wellbores. We received consideration consisting of approximately $83.0 million (approximately $81.4 million as adjusted) cash and 1,052,632 common units of SPP valued at approximately $2.0 million as of the date of the closing (as discussed further in Note 8, "Investments"). The Company did not record any gains or losses related to the Palmetto disposition.

Pro Forma Operating Results

The following unaudited pro forma combined results for the three and nine months ended September 30, 2015 and 2014 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 Palmetto disposition had occurred on January 1, 2014. The pro forma information includes adjustments primarily for revenues and expenses from the acquired and disposed properties, depreciation, depletion, amortization and accretion, impairment, interest expense and debt issuance cost amortization for acquisition debt, consideration received including cash and common stock, 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.

· The Palmetto disposition completed on March 31, 2015.

· Issuance of the Original 6.125% Notes (as discussed in Note 6, "Long-Term Debt") to finance a portion of the Catarina acquisition and the related adjustments to interest expense.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues	$ 114,526	$ 195,937	$ 363,005	$ 614,578
Net income (loss) attributable to common stockholders	$ (421,024)	$ 42,150	$ (1,442,100)	$ 18,483
Net income (loss) per common share, basic and diluted	$ (7.33)	$ 0.76	$ (25.24)	$ 0.38

The unaudited 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 acquisition and related financings and Palmetto disposition been completed as of the dates set forth in this unaudited 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 unaudited pro forma combined financial information for a number of reasons, including, but not limited to, differences in assumptions used to prepare the unaudited pro forma combined financial information and actual results.

Table of Contents

Note 4. Cash and Cash Equivalents

As of September 30, 2015 and December 31, 2014, cash and cash equivalents consisted of the following (in thousands):

	September 30, 2015	December 31, 2014
Cash at banks	$ 76,544	$ 73,528
Money market funds	120,340	400,186
Total cash and cash equivalents	$ 196,884	$ 473,714

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. During the three and nine month periods ended September 30, 2015, the Company recorded a full cost ceiling test impairment after income taxes of $454.6 million and $1,365.0 million, respectively. Based on the sustained decline in average prices throughout the first three quarters of 2015 and a current expectation that prices will remain unfavorable during the remainder of 2015 based upon the current NYMEX forward prices, absent a material addition to proved reserves and/or a material reduction in future development costs, we believe that there is a reasonable likelihood that the

Company will incur additional impairments to our full cost pool in 2015. No impairment expense was recorded for the three and nine month periods ended September 30, 2014.

Costs associated with unproved properties and properties under development, including costs associated with seismic data, leasehold acreage and the current drilling of wells, are excluded from the full cost amortization base until the properties have been evaluated. Unproved properties are identified on a project basis, with a project being an area in which significant leasehold interests are acquired within a contiguous area. Unproved properties are reviewed periodically by management and when management determines that a project area has been evaluated through drilling operations or a thorough geologic evaluation, the project area is transferred into the full cost pool subject to 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 September 30, 2015, consisted of $1.15 billion face value of 6.125% senior notes (the “6.125% Notes,” consisting of $850 million in Original 6.125% Notes and $300 million in Additional 6.125% Notes (defined below), which were issued at a premium to face value of approximately $2.3 million) maturing on January 15, 2023, and $600 million principal amount of 7.75% senior notes (the “7.75% Notes,” consisting of $400 million in Original 7.75% Notes (defined below) and $200 million in Additional 7.75% Notes (defined below), which were issued

Table of Contents

at a discount to face value of approximately $7.0 million), maturing on June 15, 2021. As of September 30, 2015, and December 31, 2014, the Company's long term debt consisted of the following:

			Amount Outstanding (in thousands) as of	
	Interest Rate	Maturity date	September 30, 2015	December 31, 2014
Second Amended and Restated Credit Agreement	Variable	June 30, 2019	$ —	$ —
7.75% Notes	7.75%	June 15, 2021	600,000	600,000
6.125% Notes	6.125%	January 15, 2023	1,150,000	1,150,000
			1,750,000	1,750,000
Unamortized discount on Additional 7.75% Notes			(5,160)	(5,837)
Unamortized premium on Additional 6.125% Notes			1,967	2,100
Total long-term debt			$ 1,746,807	$ 1,746,263

The components of interest expense are (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Interest on Senior Notes	$ (29,234)	$ (25,316)	$ (87,704)	$ (48,999)
Interest expense and commitment fees on credit agreement	(301)	(384)	(940)	(1,277)
Amortization of debt issuance costs	(1,748)	(1,710)	(5,312)	(7,215)
Amortization of discount on Additional 7.75% Notes	(226)	(227)	(678)	(679)
Amortization of premium on Additional 6.125% Notes	67	25	134	25
Total interest expense	$ (31,442)	$ (27,612)	$ (94,500)	$ (58,145)

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 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 (the "Amended and

Restated Credit Agreement”). The Amended and Restated Credit Agreement was to mature on May 31, 2018.

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

Second Amended and Restated Credit Agreement: On June 30, 2014, the Company, each of SEP III, SN Marquis, SN Cotulla, SN Operating LLC (“SN Operating”), SN TMS, LLC (“SN TMS”), and SN Catarina, LLC (“SN Catarina” and together with SEP III, SN Marquis, SN Cotulla, SN Operating and SN TMS, collectively, the “Guarantors” and the Guarantors and the Company collectively, the “Loan Parties”), entered into a revolving credit facility represented by a $1.5 billion Second Amended and Restated Credit Agreement with Royal Bank of Canada as the administrative agent (the “Administrative Agent”), Capital One, National Association as the syndication agent, Compass Bank and SunTrust Bank as documentation agents, RBC Capital Markets as sole lead arranger and sole book runner and the lenders party thereto (the “Second Amended and Restated Credit Agreement”). The Company has elected an aggregate elected commitment amount under the Second Amended and Restated Credit Agreement of $300 million. Additionally, the Second Amended and Restated Credit Agreement provides for the issuance of letters of credit, limited to an aggregate amount of the lesser of $80 million and the total availability thereunder. As of September 30, 2015, there were no borrowings and no letters of credit outstanding under the Second Amended and Restated Credit Agreement. Availability under the Second Amended and Restated Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base and aggregate elected commitment amount. The borrowing base under the Second Amended and Restated Credit Agreement was set at $362.5 million upon issuance of the Additional 6.125% Notes and was increased to $650 million in connection with the October 1, 2014 redetermination. However, the Company’s aggregate elected commitment amount remained $300 million and the Company retained the ability to increase the aggregate elected commitment up to the $650 million approved borrowing base upon written notice from the

Table of Contents

Company and compliance with certain conditions, including the consent of any lender whose elected commitment is increased. On March 31, 2015, pursuant to an amendment of the Second Amended and Restated Credit Agreement, the borrowing base under such agreement was changed to $550 million, with the aggregate elected commitment amount of $300 million remaining unchanged. The borrowing base was reduced as a result of several factors that included the decrease in reserve value from the decline in commodity prices along with the reduction in reserves in connection with the Palmetto disposition discussed above partially offset by underlying new reserve growth through drilling. All of the aggregate elected commitment was available for future revolver borrowings as of September 30, 2015.

The Second Amended and Restated Credit Agreement matures on June 30, 2019. The borrowing base under the Second Amended and Restated Credit Agreement can be subsequently re-determined up or down by the lenders based on, among other things, their evaluation of the Company's and its restricted subsidiaries' oil and natural gas reserves. Redeterminations of the borrowing base are scheduled to occur semi-annually on or before April 1 and October 1 of each year. The borrowing base is also subject to (i) automatic reduction by 25% of the amount of any increase in the Company's high yield debt, (ii) interim redetermination at the election of the Company once between each scheduled redetermination, (iii) interim redetermination at the election of the administrative agent at the direction of a majority of the credit exposures or, if none, the elected commitments of the lenders once between each scheduled re-determination and (iv) if the required lenders so direct in connection with asset sales and swap terminations involving more than 10% of the value of the proved developed oil and gas properties included in the most recent reserve report, reduction in an amount equal to the borrowing base value, as determined by the administrative agent in its reasonable judgment, of the assets so sold and swaps so terminated.

The Company's obligations under the Second Amended and Restated Credit Agreement are secured by a first priority lien on substantially all of the Company's assets and the assets of its 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 Second Amended and Restated 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 Second Amended and Restated 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 elected commitment.

The Second Amended and Restated 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 Second Amended and Restated Credit Agreement also provides for cross default between the Second Amended and Restated Credit Agreement and the other debt (including debt under the 6.125% Notes and the 7.75% Notes) and obligations in respect of hedging agreements (on a mark-to-market basis), of the Company and its restricted subsidiaries, in an aggregate principal amount in excess of $10 million. Furthermore, the Second Amended and Restated Credit Agreement contains financial covenants that require the Company to satisfy the following tests: (i) current assets plus undrawn borrowing capacity on the Second Amended and Restated Credit Agreement to current liabilities of at least 1.0 to 1.0 at all times, and (ii) senior secured debt to consolidated last twelve months ("LTM") EBITDA of not greater than 2.25 to 1.0 as of the last day of any fiscal quarter

On July 20, 2015, the Company, the Guarantors, the Administrative Agent and the other agents and lenders party thereto entered into the Third Amendment to the Second Amended and Restated Credit Agreement (the "Third Amendment") which amended the Second Amended and Restated Credit Agreement, among other things, to (a) permit one or more of the Loan Parties to (i) make direct and indirect investments of up to $10 million in an unrestricted subsidiary in connection with a joint venture to develop a midstream facility and (ii) enter into and perform certain commercial and financial support agreements with such joint venture and the other party to such joint venture on terms acceptable to the Administrative Agent, (b) permits the Loan Parties to (i) acquire an undivided interest in a midstream facility, (ii) make up to $80 million of direct and indirect investments in an unrestricted subsidiary in connection with a joint venture to develop, own and operate midstream assets to be entered into by such unrestricted subsidiary, (iii) enter into and perform midstream services agreements with the other party to such joint venture on terms acceptable to the Administrative Agent, (iv) enter into and perform financial support agreements with such joint venture and the other party to such joint venture on terms acceptable to the Administrative Agent, (v) if the Loan Party that acquires such undivided interest in a midstream facility so elects, exchange such undivided interest in whole or in part for equity interests in such joint venture in an amount equal to the lesser of (X) 2% of the equity interests in such joint venture and (Y) equity interests having a value no greater than $5 million, as determined by the Company in good faith at such time and (vi) retain and grant security interests over any such equity interests so acquired, (c) permits the Loan Parties to (i) dispose of certain midstream assets to an unrestricted subsidiary, (ii) dispose of such midstream assets or equity interests in such unrestricted subsidiary in exchange for consideration, up to 25% by value of which may include equity interests in the transferee and payment-in-kind notes issued by the transferee or, if equity interests in such transferee are not publicly traded, its parent entity that has issued publicly traded equity interests, (iii) retain such equity interests and payment-in-kind notes, (iv) retain joint and several liability in connection with such midstream assets to the extent required under the terms of the lease under which they were acquired and (v) enter into midstream services agreements with such transferee on terms acceptable to the Administrative Agent, (d) eliminate the covenant requiring that the Borrower maintain a ratio of consolidated EBITDA to consolidated net interest expense of not less than 2.25 to 1.0, (e) adjust the limits on the Loan Parties entering into swap agreements relative to expected production from proved developed producing reserves and total proved reserves and permit the Loan Parties, within stated limits, to enter into swap agreements in connection with the contemplated acquisition of proved developed producing reserves and total proved reserves and (f) provide for other technical amendments.

On September 29, 2015, the Company, the Guarantors, the Administrative Agent and the other agents and lenders party thereto entered into the Fourth Amendment to the Second Amended and Restated Credit Agreement (the “Fourth Amendment”) which amended the Second Amended and Restated Credit Agreement, among other things, to (a) permit one or more lenders in addition to Royal Bank of Canada to act as issuing bank upon agreement with such lenders, (b) increase the letter of credit sublimit to $80 million, (c) permit the Loan Parties to enter into and perform certain commercial and financial support agreements in connection with one of the joint ventures to develop a midstream facility permitted by the Third Amendment, (d) substitute references to Catarina Midstream, LLC (“Catarina Midstream”) in place of references to the “DW Midstream Unrestricted Subsidiary” and update the organizational chart and subsidiary list in the schedules to the Second Amended and Restated Credit Agreement to reflect Catarina Midstream’s existence and status as an unrestricted subsidiary until such time as it is disposed of in accordance with the Second Amended and Restated Credit Agreement, (e) permit the disposition of units in SPP by a Loan Party to Catarina Midstream, (f) permit certain repurchases of equity interests in the Company by the Loan Parties and (g) provide for other technical amendments, clarifications and corrections. Subsequent to quarter end, on October 30, 2015, the Company, the Guarantors, the Administrative Agent and the other agents and lenders party thereto entered into the Fifth Amendment to the Second Amended and Restated Credit Agreement (the “Fifth Amendment”) to modify certain representations, covenants, exhibits and schedules and to waive any existing breaches of, and any resulting defaults or events of default with respect to certain covenants of the Second Amended and Restated Credit Agreement, all as further discussed in Note 18, “Subsequent Events.”

From time to time, the agents, arrangers, book runners and lenders under the Second Amended and Restated 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 September 30, 2015, the Company was in compliance with the covenants of the Second Amended and Restated Credit Agreement.

7.75% Senior Notes Due 2021

On June 13, 2013, we completed a private offering of $400 million in aggregate principal amount of the Company's 7.75% senior notes that will mature on June 15, 2021 (the "Original 7.75% 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 7.75% 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.

On September 18, 2013, we issued an additional $200 million in aggregate principal amount of our 7.75% senior notes due 2021 (the "Additional 7.75% Notes" and, together with the Original 7.75% Notes, the 7.75% Notes) in a private offering at an issue price of 96.5% of the principal amount of the Additional 7.75% Notes. We received net proceeds of approximately $188.8 million (after deducting the initial purchasers' discounts and offering expenses of

Table of Contents

$4.2 million) from the sale of the Additional 7.75% Notes. The Company also received cash for accrued interest from June 13, 2013 through the date of issuance of $4.1 million, for total net proceeds of $192.9 million from the sale of the Additional 7.75% Notes. The Additional 7.75% Notes were issued under the same indenture as the Original 7.75% Notes, and are therefore treated as a single class of debt 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 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 Second Amended and Restated Credit Agreement) to the extent of the value of the assets securing such debt. The 7.75% Notes are fully and unconditionally guaranteed (except for customary release provisions) 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, assume, or guarantee additional indebtedness or issue certain types of equity securities; (ii) pay distributions on, 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; (vii) restrict distributions or other payments from the Company's restricted subsidiaries; and (ix) designate subsidiaries as unrestricted subsidiaries.

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 not greater than the net cash proceeds of 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.

On July 18, 2014, we completed an exchange offer of $600 million aggregate principal amount of the 7.75% Notes that had been registered under the Securities Act of 1933, as amended (the "Securities Act"), for an equal amount of the 7.75% Notes that had not been registered under the Securities Act.

6.125% Senior Notes Due 2023

On June 27, 2014, the Company completed a private offering of the Original 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 offering expenses, which the Company used to repay all of the $100 million in borrowings outstanding under its Amended and Restated Credit Agreement and to finance a portion of the purchase price of the Catarina acquisition. We used the remaining proceeds from the offering to fund a portion of the remaining 2014 capital budget and for general corporate purposes. The Original 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.

On September 12, 2014, we issued an additional $300 million in aggregate principal amount of our 6.125% senior notes due 2023 (the "Additional 6.125% Notes" and, together with the Original 6.125% Notes, the 6.125% Notes and, together with the 7.75% Notes, the "Senior Notes") in a private offering at an issue price of 100.75% of the principal amount of the Additional 6.125% Notes. We received net proceeds of $295.9 million, after deducting the initial purchasers' discounts, adding premiums to face value of $2.3 million and deducting offering expenses of $6.4 million. The Company also received cash for accrued interest from June 27, 2014 through the date of the issuance of $3.8 million, for total net proceeds of $299.7 million from the sale of the Additional 6.125% Notes. The Additional 6.125% Notes were issued under the same indenture as the Original 6.125% Notes, and are therefore treated as a single class of securities under the indenture. We used a portion of the net proceeds from the offering to fund a portion of the 2014 capital budget and intend to use the remainder of the net proceeds to fund a portion of the 2015 capital budget, and for general corporate purposes.

The 6.125% Notes are senior unsecured obligations and rank equally in right of payment with all of our existing and future senior unsecured indebtedness. The 6.125% Notes rank senior in right of payment to our future subordinated indebtedness. The 6.125% Notes are effectively junior in right of payment to all of our existing and future secured debt (including under the Second Amended and Restated Credit Agreement) to the extent of the value of the assets securing such debt. The 6.125% Notes are fully and unconditionally guaranteed (except for customary release provisions) 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 of our subsidiaries 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 our ability and our restricted subsidiaries' ability 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.

We have 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 unpaid interest and additional interest, if any, to the redemption date, at any time prior to July 15, 2018. In addition, we may redeem up to 35% of the 6.125% Notes prior to July 15, 2017 under certain circumstances with an amount not greater than the net cash proceeds of one or more equity offerings at the redemption price specified in the indenture. We may also be required to repurchase the 6.125% Notes upon a change of control or if we sell certain of our assets.

On February 27, 2015, we completed an exchange offer of $1.15 billion aggregate principal amount of the 6.125% Notes that had been registered under the Securities Act for an equal amount of the 6.125% Notes that had not been registered under the Securities Act.

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. The Company further uses enhanced swaps for a portion of its commodity price hedging activities. An enhanced swap is a product created by simultaneously selling an out of the money put and using the premium value from the sale to modify or "enhance" the value of a swap executed at the same time. The transaction provides an absolute minimum price at the enhanced swap strike price until the put strike price level is reached at which point the Company receives the market price plus the difference between the enhanced swap price and the put strike price. The Company also enters into puts to hedge production at a floor price, but allows the Company to realize revenue upside if oil prices on the hedged volumes increase above the floor price. In order to enter into these put derivative transactions, the Company pays a fixed deferred premium when each trade is settled. 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

Table of Contents

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 September 30, 2015, the Company had the following NYMEX WTI crude oil swaps and puts, respectively, covering anticipated future production:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
October - December 2015	1,288,000	$ 73.23	$ 67.00 - $ 88.35
2016	2,562,000	$ 70.11	$ 62.00 - $ 80.15

Calendar Year	Volumes (Bbls)	Put Price per Bbl	Put Price Range per Bbl
2016	4,026,000	$ 60.00	$ 60.00 - $ 60.00

As of September 30, 2015, the Company had the following NYMEX Henry Hub natural gas swaps, three-way collars, and enhanced swaps, respectively, covering anticipated future production:

Calendar Year	Swap Volumes (Mmbtu)	Average Price per Mmbtu	Price Range per Mmbtu
October - December 2015	2,150,000	$ 3.90	$ 3.54 - $ 4.01
2016	14,640,000	$ 3.87	$ 3.80 - $ 3.92
2017	3,650,000	$ 3.65	$ 3.65

Calendar Year	Three-way Collar Volumes (Mmbtu)	Average Short Put Price per Mmbtu	Average Long Put Price per Mmbtu	Average Short Call Price per Mmbtu
October - December 2015	920,000	$ 3.50	$ 4.00	$ 4.90

Calendar Year	Enhanced Swap Volumes (Mmbtu)	Average Swap Price per Mmbtu	Average Put Price per Mmbtu
October - December 2015	2,852,000	$ 4.31	$ 3.75

The following table sets forth a reconciliation of the changes in fair value of the Company's commodity derivatives for the nine months ended September 30, 2015 and the year ended December 31, 2014 (in thousands):

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014
Beginning fair value of commodity derivatives	$ 123,316	$ (3,397)
Net gains on crude oil derivatives	120,894	115,602
Net gains on natural gas derivatives	15,204	21,603
Net settlements on derivative contracts:		
Crude oil	(83,948)	(4,503)
Natural gas	(13,033)	(1,097)
Net premiums on derivative contracts:		
Crude oil	—	(4,892)
Ending fair value of commodity derivatives	$ 162,433	$ 123,316

Table of Contents

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):

	September 30, 2015		
	Gross Amount of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 136,123	$ (4,132)	$ 131,991
Long-term asset	30,442	—	30,442
Total asset	$ 166,565	$ (4,132)	$ 162,433
Offsetting Derivative Liabilities:			
Current liability	$ (4,132)	$ 4,132	$ —
Long-term liability	—	—	—
Total liability	$ (4,132)	$ 4,132	$ —

	December 31, 2014		
	Gross Amount of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 194,953	$ (94,772)	$ 100,181
Long-term asset	24,024	—	24,024
Total asset	$ 218,977	$ (94,772)	$ 124,205
Offsetting Derivative Liabilities:			
Current liability	$ (94,772)	$ 94,772	$ —
Long-term liability	(889)	—	(889)
Total liability	$ (95,661)	$ 94,772	$ (889)

Note 8. Investments

On March 31, 2015, a subsidiary of the Company received approximately $2 million in common units of SPP as part of the consideration paid for the Palmetto disposition described in Note 3, “Acquisitions and Divestitures.” Rather than accounting for the investment under the equity method, the Company elected the fair value option to account for its interest in SPP.

The Company records the equity investment in SPP at fair value at the end of each reporting period. Any gains or losses are recorded as a component of other income (expense) in the consolidated statement of operations. The Company recorded losses related to the investment in SPP for the three and nine months ended September 30, 2015 of $0.9 million and $0.8 million, respectively.

Subsequent to the quarter end, the Company contributed all of the 1,052,632 common units of SPP (105,263 common units after a 1-for-10 reverse split completed by SPP on August 3, 2015) received in connection with the Palmetto disposition as described above. Please see additional discussion on this transaction in Note 18, “Subsequent Events.”

Table of Contents

Note 9. 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.

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 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 September 30, 2015 and December 31, 2014 (in thousands):

	As of September 30, 2015 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	$ 120,340	$ —	$ —	$ 120,340
Equity investment:				
Investment in SPP	1,136	—	—	1,136
Oil derivative instruments:				
Swaps	—	88,322	—	88,322
Puts	—	51,448	—	51,448
Gas derivative instruments:				
Swaps	—	20,619	—	20,619
Enhanced Swaps	—	1,588	—	1,588
Three-way collars	—	456	—	456
Total	$ 121,476	$ 162,433	$ —	$ 283,909

Table of Contents

	As of December 31, 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	$ 400,186	$ —	$ —	$ 400,186
Oil derivative instruments:				
Swaps	—	33,975	—	33,975
Enhanced Swaps	—	—	44,586	44,586
Three-way collars	—	—	24,264	24,264
Gas derivative instruments:				
Swaps	—	13,818	—	13,818
Enhanced Swaps	—	—	5,193	5,193
Three-way collars	—	—	1,480	1,480
Total	$ 400,186	$ 47,793	$ 75,523	$ 523,502

Financial Instruments: The Level 1 instruments presented in the tables above consist of money market funds included in cash and cash equivalents and equity investment on the Company's condensed consolidated balance sheets at September 30, 2015, and December 31, 2014. 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. A subsidiary of the Company received common units in SPP as part of the consideration received for the Palmetto disposition discussed in Note 3, "Acquisitions and Divestitures." The Company is accounting for these units as an equity method investment utilizing the fair value accounting method. The Company identified the common units as Level 1 instruments due to the fact that SPP is a publicly traded company on the NYSE MKT with daily quoted prices that can be easily obtained.

The Company's derivative instruments, which consist of swaps, enhanced swaps, collars and puts, are classified as Level 2 as of September 30, 2015, and either Level 2 or Level 3 as of December 31, 2014, 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. Since swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2. As of December 31, 2014, the Company's enhanced swaps, puts, collars and three-way collars included some level of unobservable inputs, such as volatility curves, and were therefore classified as Level 3. As of September 30, 2015, the Company believes that substantially all of the inputs required to calculate the fair value of enhanced swaps, puts, collars, and three-way collars are observable in the marketplace throughout the term of these derivative instruments or supported by observable levels at which transactions are executed in the marketplace, and are therefore classified as Level 2. 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.

There were no derivative instruments classified as Level 3 as of September 30, 2015. The fair values of the Company's derivative instruments classified as Level 3 as of December 31, 2014 were $75.5 million. The significant unobservable inputs for Level 3 contracts as of December 31, 2014 include unpublished forward prices of commodities, market volatility and credit risk of counterparties.

Table of Contents

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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Beginning balance	$ —	$ (16,774)	$ 75,523	$ (519)
Total gains included in earnings	—	26,189	418	8,389
Net settlements on derivative contracts(1)	—	200	(14,277)	1,745
Derivative contracts transferred to Level 2	—	—	(61,664)	—
Ending balance	$ —	$ 9,615	$ —	$ 9,615
Gains (losses) included in earnings related to derivatives still held as of September 30, 2015 and 2014	$ —	$ 26,747	$ (940)	$ 10,492

(1) Includes ($12,919) of net settlements in Level 2 that were transferred from Level 3 during the nine months ended September 30, 2015.

In February 2015, the Company modified certain of its crude oil enhanced swap and three-way collar transactions to create crude oil swaps on a costless transactional basis. As of December 31, 2014, these crude oil enhanced swaps and three way collar transactions had fair values classified as Level 3. When the transactions were modified to swaps during the first quarter of 2015, the fair values of the transactions were classified as Level 2. As of September 30, 2015, the Company believes that substantially all of the inputs required to calculate the fair value of enhanced swaps, puts, collars, and three-way collars are Level 2 and were moved out of Level 3 fair value classification.

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 allocation for the Catarina acquisition is presented in Note 3, "Acquisitions and Divestitures." Liabilities assumed include asset retirement obligations existing at the date of acquisition. 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 10, "Asset Retirement Obligations."

In connection with the exchange agreements entered into in February, May and August 2014 by the Company with certain holders of the Company's Series A Convertible Perpetual Preferred Stock ("Series A Preferred Stock") and Series B Convertible Perpetual Preferred Stock ("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 13, "Stockholders' Equity."

Fair Value of Other Financial Instruments

Financial instruments not carried at fair value consist of oil and natural gas receivables, accounts payable and accrued liabilities and long-term debt. The carrying amounts of our oil and natural gas receivables, accounts payable and accrued liabilities approximate fair value due to the highly liquid nature of these short-term instruments. The registered 7.75% Notes and 6.125% Notes are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair values of the 7.75% Notes and 6.125% Notes were $447.0 million and $747.5 million, respectively, as of September 30, 2015, and were calculated using quoted market prices based on trades of such debt as of that date.

Table of Contents

Note 10. 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 third-party 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.

The changes in the asset retirement obligation for the nine months ended September 30, 2015 and the year ended December 31, 2014 were as follows (in thousands):

	Nine Months Ended September 30, 2015	Year Ended December 31, 2014
Abandonment liability, beginning of period	$ 25,694	$ 4,130
Liabilities incurred during period	4,454	3,922
Acquisitions	—	14,723
Divestitures	(379)	—
Revisions	3,273	1,658
Accretion expense	1,517	1,261
Abandonment liability, end of period	$ 34,559	$ 25,694

During the third quarter of 2015, the Company reviewed its asset retirement obligation cost estimates, and made revisions to increase cost estimates of future asset retirement obligations from $120,000 per well to $150,000 per well to more accurately reflect current market costs. The Company reduced the future asset retirement obligations by approximately $379,000 due to the sale of working interests in properties associated with the Palmetto disposition on March 31, 2015.

Note 11. 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 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

Table of Contents

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 nine months ended September 30, 2015 and 2014 are as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Administrative fees	$ 6,694	$ 5,982	$ 19,548	$ 18,444
Third-party expenses	1,534	2,452	3,550	5,135
Total included in general and administrative expenses	$ 8,228	$ 8,434	$ 23,098	$ 23,579

As of September 30, 2015 and December 31, 2014, the Company had a net receivable from SOG and other members of the Sanchez Group of $3.8 million and $0.4 million, respectively, which are reflected as “Accounts receivable—related entities” in the condensed consolidated balance sheets. The net receivable as of September 30, 2015 and December 31, 2014 consists primarily of advances paid related to leasehold and other costs paid to SOG.

Palmetto Disposition

On March 31, 2015, we completed the Palmetto disposition discussed above to a subsidiary of SPP, which is a related party. SPP is a related party of the Company in accordance with GAAP as the common units of SPP received in connection with the Palmetto disposition constitutes an equity method investment, which the Company has elected to account for using the fair value option (see further discussion in Note 8, “Investments”).

TMS Asset Purchase

In August 2013, we acquired rights to approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS (the “TMS transaction”) for cash and shares of our common stock. In connection with the TMS transaction, 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”), which transaction included a carry on drilling costs for up to 6 gross (3 net) wells. Eduardo Sanchez, our President who is also the brother of our Chief Executive Officer and the son of our Executive Chairman of the Company’s Board of Directors (the “Board”), owns 24.05% of Sanchez Resources and is its President and Chief Executive Officer. Sanchez Resources is also indirectly owned, in part, by our Chief Executive Officer and our Executive Chairman of the Board, who each also serve on our Board. Additionally, Patricio Sanchez and Ana Lee Sanchez Jacobs, each an immediate family member of our President, Chief Executive Officer and Executive Chairman of the Board, either directly or indirectly, own equity interests in Sanchez Resources.

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.

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 approximately $7.5 million. The cash consideration provided to SR was $14.4 million, before consideration of any well carries. The acquisitions were accounted for as the purchase of assets at cost on the acquisition date. We 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 (the “Initial Well Carry”) with an option to drill an additional 6 gross (3 net) TMS wells (“Additional Wells”) within the AMI. In August 2015, the Company signed an agreement with SR whereby the Company paid SR approximately $8 million in lieu of drilling the remaining two Additional Wells (the “Buyout Agreement”). The Buyout Agreement stipulates that SN has earned full rights to all acreage stated in the TMS transaction and effectively terminates any future well carry commitments.

We plan to defer drilling on the gross Additional Wells originally planned for 2015. We do not anticipate that the plan for deferral will materially impact our ability to maintain our core acreage in the play under our leases.

Western Catarina Midstream Divestiture

On October 14, 2015, the Company and SN Catarina completed the sale of SN Catarina’s interests in Catarina Midstream, LLC, a wholly-owned subsidiary of SN Catarina, Catarina Midstream, which as of the closing owned (i)

Table of Contents

certain midstream gathering lines and associated assets and interests located in Dimmit County and Webb County, Texas and (ii) 105,263 common units of SPP, to SPP for approximately $345.8 million in cash, subject to post-closing adjustments (the “Western Catarina Midstream Divestiture”). In connection with the closing of the Western Catarina Midstream Divestiture, SN Catarina and Catarina Midstream entered into a Firm Gathering and Processing Agreement (the “Gathering Agreement”) on October 14, 2015 for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas will be dedicated for gathering by Catarina Midstream. In addition, for the first five years of the Gathering Agreement, SN Catarina will be required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. SN Catarina will be required to pay gathering and processing fees of $0.96 per barrel for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through the gathering system, in each case, subject to an annual escalation for a positive increase in the consumer price index. In addition, SN Catarina has, under certain circumstances, a right of first refusal during the term of the agreement and afterwards with respect to dispositions by Catarina Midstream of its ownership interest in the gathering system. The Company has accounted for the Western Catarina Midstream Divestiture as a sale of assets and subsequent leaseback of the assets over the 15 year Gathering Agreement term. The Company has recorded a deferred gain upon closing of the transaction that will be amortized straight-line over five years resulting in a reduction to lease operating expense.

Note 12. Accrued Liabilities

The following information summarizes accrued liabilities as of September 30, 2015 and December 31, 2014 (in thousands):

	September 30, 2015	December 31, 2014
Capital expenditures	$ 72,094	$ 162,726
Other:		
General and administrative costs	6,149	830
Production taxes	2,390	3,137
Ad valorem taxes	4,875	1,994
Lease operating expenses	24,286	22,354
Interest payable	28,281	37,743
Leasehold improvements	—	1,104
Total accrued liabilities	$ 138,075	$ 229,888

Note 13. Stockholders’ Equity

Common Stock Offerings—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 $167.5 million, after deducting underwriters' fees and offering expenses of $8.7 million. The Company used the net proceeds from the offering to partially fund the 2014 capital budget and for general corporate purposes.

Series A Preferred Stock Offering—On September 17, 2012, the Company completed a private placement of 3,000,000 shares of Series A Preferred Stock, which were sold to a group of qualified institutional buyers pursuant to the Rule 144A exemption from registration under the Securities Act. The issue price of each share of the Series A 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 of $5.5 million.

Each share of Series A Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.325 shares of common stock per share of Series A 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, approximately 4,275,640 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Series A Preferred Stock.

The annual dividend on each share of Series A 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. The Company may, at its option, pay dividends in cash and, subject to certain conditions, common stock or any combination thereof. Dividends are cumulative, and as of September 30, 2015, all dividends accumulated through that date had been paid.

Except as required by law or the Company's Amended and Restated Certificate of Incorporation (the "Charter"), holders of the Series A 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 Preferred Stock and the holders of the Series B 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 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 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 Preferred Stock as a result of the fundamental change.

Series B Preferred Stock Offering—On March 26, 2013, the Company completed a private placement of 4,500,000 shares of Series B Preferred Stock. The issue price of each share of the Series B 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 Preferred Stock is convertible at any time at the option of the holder thereof at an initial conversion rate of 2.337 shares of common stock per share of Series B 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, approximately 8,255,055 shares of common stock would be issuable upon conversion of all of the outstanding shares of the Series B Preferred Stock.

The annual dividend on each share of Series B 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. Dividends are cumulative, and as of September 30, 2015, all dividends accumulated through that date had been paid.

Except as required by law or the Charter, holders of the Series B 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 Preferred Stock and the holders of the Series A 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 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 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 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 Series A Preferred Stock, and of Series B Preferred Stock, pursuant to which such holders agreed to exchange an aggregate of (i) 947,490 shares of Series A Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 2,425,574 shares of the

Table of Contents

Company's common stock, and (ii) 756,850 shares of the Series B Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 2,021,066 shares of common stock.

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

Further, on August 28, 2014, the Company entered into exchange agreements with certain holders (the "August 2014 Holders," and together with the May 2014 Holders and the February 2014 Holders, the "Holders") of the Series A Preferred Stock, pursuant to which such holders agreed to exchange an aggregate of 47,500 shares of Series A Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 119,320 shares of the Company's 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 Preferred Stock and Series B 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, $3.1 million and $0.3 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 in connection with the exchange agreements entered into in February, May and August 2014, respectively, has been reflected as an additional preferred stock dividend, that is, as an increase in accumulated deficit to arrive at net loss attributable to common shareholders in our condensed consolidated financial statements.

NOL Rights Plan—On July 28, 2015, the Company entered into a net operating loss carryforwards ("NOLs") rights plan (the "Rights Plan") with Continental Stock Transfer & Trust Company, as rights agent. In connection therewith, the Board declared a dividend of one preferred share purchase right ("Right") for each outstanding share of the Company's common stock. The dividend was paid on August 10, 2015 to stockholders of record as of the close of business on August 7, 2015 (the "NOL Record Date"). In addition, one Right automatically attached to each share of common stock issued between the NOL Record Date and such date as when the Rights become exercisable.

The Board adopted the Rights Plan in an effort to prevent the imposition of significant limitations under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), on its ability to utilize its current NOLs to reduce its future tax liabilities. If the Company experiences an "ownership change," as defined in Section 382 of the Code, the Company's ability to fully utilize the NOLs on an annual basis will be substantially limited, and the timing of the usage of the NOLs could be substantially delayed, which could therefore significantly impair the value of those benefits. In general terms, the Rights Plan works by imposing a significant penalty upon any person or group that acquires 4.9% or more of the outstanding common stock without the approval of the Board (an "Acquiring Person"). The Rights Plan also gives discretion to the Board to determine that someone is an Acquiring Person even if they do not own 4.9% or more of the outstanding common stock but do own 4.9% or more in value of the Company's outstanding stock, as determined pursuant to Section 382 of the Code and the regulations promulgated thereunder. Stockholders who currently own 4.9% or more of the common stock will not trigger the Rights unless they acquire additional common stock shares, subject to certain exceptions set forth in the Rights Plan. In addition, the Board has established procedures to consider requests to exempt certain acquisitions of the Company's securities from the Rights Plan if the Board determines that doing so would not limit or impair the availability of the NOLs or is otherwise in the best interests of the Company.

Table of Contents

Earnings (Loss) Per Share—The following table shows the computation of basic and diluted net loss per share for the three and nine months ended September 30, 2015 and 2014 (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$ (416,860)	$ 49,031	$ (1,477,115)	$ 40,318
Less:				
Preferred stock dividends	(3,991)	(4,274)	(11,973)	(29,599)
Net loss allocable to participating securities(1)	—	(2,068)	—	(495)
Net income (loss) attributable to common stockholders	$ (420,851)	$ 42,689	$ (1,489,088)	$ 10,224
Weighted average number of unrestricted outstanding common shares used to calculate basic net earnings (loss) per share	57,426	55,732	57,141	51,153
Dilutive shares(2)(3)(4)	—	12,608	—	—
Denominator for diluted earnings (loss) per common share	57,426	68,340	57,141	51,153
Net income (loss) per common share - basic	$ (7.33)	$ 0.77	$ (26.06)	$ 0.20
Net income (loss) per common share - diluted	$ (7.33)	$ 0.69	$ (26.06)	$ 0.20

(1) For the three and nine months ended September 30, 2015, 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 nine months ended September 30, 2015 excludes 597,910 and 2,663,010 shares of weighted average restricted stock and 12,530,695 shares of common stock resulting from an assumed conversion of the Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive.

(3) The nine months ended September 30, 2014 excludes 1,290,637 shares of weighted average restricted stock and 13,863,738 shares of common stock resulting from an assumed conversion of the Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were anti-dilutive.

(4) The three months ended September 30, 2014 includes 12,607,521 shares of common stock resulting from an assumed conversion of the Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted earnings per common share as these shares were dilutive. In addition, the related preferred stock dividends of $4,274,445 were not deducted from net income in computing the numerator used in the calculation of diluted earnings per common share.

Note 14. Stock Based Compensation

At the Annual Meeting of Stockholders of the Company held on May 21, 2015 (“2015 Annual Meeting”), the Company’s stockholders approved the Sanchez Energy Corporation Second Amended and Restated 2011 Long Term Incentive Plan (the “LTIP”). The Board had previously approved the LTIP on April 20, 2015, subject to stockholder approval.

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 (i) 4,000,000 shares of common stock plus the number of shares of common stock available under the predecessor to the LTIP on the record date of the 2015 Annual Meeting (the "Record Date") at which the stockholders approved the LTIP as well as (ii) upon the issuance of additional shares of common stock from time to time after the Record Date, an automatic increase of 15% of such issuance of additional shares of 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

Table of Contents

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 or the Compensation Committee of the Board as appointed 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.

For the restricted stock awards granted to non-employees, stock-based compensation expense is based on fair value re-measured 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.

During the three and nine months ended September 30, 2015, the Company issued 0 and 95,200 shares, respectively, of restricted common stock pursuant to the LTIP to directors of the Company.

During the three and nine months ended September 30, 2015, the Company also issued approximately 229,600 and 3.3 million shares, respectively, of restricted common stock pursuant to the LTIP to certain employees (including the Company’s officers) and consultants of SOG, with whom the Company has a services agreement. These shares of restricted common stock vest in equal annual amounts over a three-year period. The Company recognized the following stock-based compensation expense (in thousands) which is included in general and administrative expense in the condensed consolidated statements of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Restricted stock awards, directors	$ 274	$ 171	$ 842	$ 731
Restricted stock awards, non-employees	81	(161)	15,082	25,157
Total stock-based compensation expense	$ 355	$ 10	$ 15,924	$ 25,888

Based on the $6.15 per share closing price of the Company's common stock on September 30, 2015, there was approximately $20.7 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 2.1 years.

29

Table of Contents

A summary of the status of the non-vested shares for the nine months ended September 30, 2015 and 2014 is presented below (in thousands):

	Nine Months Ended	
	September 30, 2015	September 30, 2014
Non-vested common stock, beginning of period	2,718	1,758
Granted	3,421	1,966
Vested	(1,601)	(692)
Forfeited	(117)	(313)
Non-vested common stock, end of period	4,421	2,719

As of September 30, 2015, approximately 5.3 million shares remain available for future issuance to participants.

Note 15. Income Taxes

The Company's effective tax rate for the nine months ended September 30, 2015 and 2014 was (0.5)% and 35.3%, respectively. 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 (0.5)% for the nine months ended September 30, 2015 is primarily related to the valuation allowance on deferred tax assets. 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 35.3% for the nine months ended September 30, 2014 is related to non-deductible general and administrative expenses recorded during the period.

The Company’s effective tax rate for the three months ended September 30, 2015 and 2014 was 0% and 35.2%, respectively. 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 0% for the three months ended September 30, 2015 is primarily related to the valuation allowance on deferred tax assets. 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 35.2% for the three months ended September 30, 2014 is primarily related to non-deductible general and administrative expenses recorded during the period.

As of September 30, 2015, the Company had estimated NOLs of $656.5 million, which begin to expire in 2031.

The Company provides for deferred income taxes on the difference between the tax basis of an asset or liability and its carrying amount in the financial statements in accordance with authoritative guidance for accounting for income taxes. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is recovered or settled, respectively. 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, management is not able to determine that it is more likely than not that the deferred tax assets will be realized and, therefore, has established a valuation allowance of $519.2 million to reduce the net deferred tax asset to $0 at September 30, 2015. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

At September 30, 2015, the Company had no material uncertain tax positions.

Note 16. Commitments and Contingencies

From time to time, the Company may be involved in lawsuits that arise in the normal course of its business. We are not aware of any material governmental proceedings against us or contemplated to be brought against us.

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 (Friedman v. A.R. Sanchez, Jr. et al., No. 9158; City of Roseville Employees'

Table of Contents

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 (collectively, the ‘‘Consolidated Derivative Actions’’)).

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 alleged 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 the defendants filed a motion to dismiss on April 1, 2014. Briefing concerning the motions to dismiss concluded on June 27, 2014. A hearing was held on August 11, 2014, on the motions to dismiss, and the court subsequently granted the motions to dismiss. The plaintiffs appealed the case to the Delaware Supreme Court for which the parties fully briefed the appeal and provided oral argument. On October 2, 2015, the Delaware Supreme Court reversed the motions to dismiss and remanded the case to the Court of Chancery of the State of Delaware. No scheduling order for the matter has been set at this time. 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 complaint alleged 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. After the motions to dismiss were granted in the Delaware Derivative Action, the parties entered into another agreed stay pending the appeal of the Delaware Derivative Action to the Delaware Supreme Court. This stay was entered by the court on February 5, 2015. Since the Delaware Supreme Court has ruled on the appeal, the parties are conferring on how to proceed with the case. This action is in its preliminary stages, and the Company is unable to reasonably predict an outcome or to estimate a range of reasonably 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 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. Such drilling obligation requires us to drill (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. 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.

As of September 30, 2015, the Company had $65.9 million in lease payment obligations that satisfy operating lease criteria. These obligations include: (i) $52.1 million for a new corporate office lease that commenced in the fourth quarter of 2014 and has an expiration date in March 2025, (ii) $7.1 million for a ground lease agreement for land owned by the Calhoun Port Authority that commenced during the third quarter of 2014 and has an expiration date in August 2024 and (iii) $6.8 million for a 10 year acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas. This acreage lease agreement includes a contractual requirement for the Company to spend a minimum of $4 million to make permanent improvements over the ten year life of the lease. The lease agreement does not specify the timing for such improvements to be made within the lease term.

The Company's ground lease with the Calhoun Port Authority is terminable upon 180 days written notice by the Company to the lessor in addition to a $1 million termination payment. The Company has the right to terminate its lease obligation for its acreage in Kenedy County, Texas at any time without penalty with nine months advanced written notice and payment of any accrued leasehold expenses.

Table of Contents

Note 17. Subsidiary Guarantors

The Company filed registration statements on Form S-3 with the SEC, which became effective January 14, 2013 and June 11, 2014 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 September 30, 2015, 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 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 the 7.75% Notes, which are guaranteed by its subsidiaries named therein. As of September 30, 2015, 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 and any non-guarantor subsidiaries of the Company are ‘‘minor’’ within the meaning of Rule 3-10 of Regulation S-X.

The Company also filed a registration statement on Form S-4 with the SEC, which became effective on January 23, 2015, pursuant to which the Company completed an offering of the 6.125% Notes, which are guaranteed by its subsidiaries named therein. As of September 30, 2015, 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 and any non-guarantor subsidiaries of the Company are ‘‘minor’’ within the meaning of Rule 3-10 of Regulation S-X.

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 18. Subsequent Events

Western Catarina Midstream Divestiture

On October 14, 2015, the Company and SN Catarina completed the Western Catarina Midstream Divestiture. In connection with the closing of the Western Catarina Midstream Divestiture, SN Catarina and Catarina Midstream entered into the Gathering Agreement on October 14, 2015 for an initial term of 15 years under which production from approximately 35,000 acres in Dimmit County and Webb County, Texas will be dedicated for gathering by Catarina Midstream. In addition, for the first five years of the Gathering Agreement, SN Catarina will be required to meet a minimum quarterly volume delivery commitment of 10,200 barrels per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments. SN Catarina will be required to pay gathering and processing fees of $0.96 per barrel for crude oil and condensate and $0.74 per Mcf for natural gas that are tendered through the gathering system, in each case, subject to an annual escalation for a positive increase in the consumer price index. In addition, SN Catarina has, under certain circumstances, a right of first refusal during the term of the agreement and afterwards with respect to dispositions by Catarina Midstream of its ownership interest in the gathering system. The Company has accounted for the Western Catarina Midstream Divestiture as a sale of assets and subsequent leaseback of the assets over the 15 year Gathering Agreement term. The Company has recorded a deferred gain upon closing of the transaction that will be amortized straight-line over five years resulting in a reduction to lease operating expense.

Midstream Joint Venture

On October 2, 2015, the Company entered into joint venture agreements with an affiliate of Targa Resources Partners LP ("Targa") to, among other things, construct a new cryogenic natural gas processing plant and an associated high pressure gathering pipelines near the Company’s Catarina asset in the Eagle Ford Shale. The processing plant, which will be located in La Salle County, Texas, is expected to have initial capacity of 200 MMcf per day with the ability to increase to 260 MMcf per day. In connection with the joint venture agreements, the Company intends to invest approximately $115 million and receive a 50% ownership interest in the joint venture owning the plant as well as in a gathering joint venture that will own approximately 45 miles of high pressure gathering pipelines that will connect the Company's existing Catarina gathering system to the plant. Targa will hold all of the transportation capacity on the pipeline, and the gathering joint venture will receive fees for transportation.

Table of Contents

The Company has firm capacity for 125,000 Mcf per day of plant processing and associated pipeline capacity for the first five years and has dedicated the Catarina acreage and all production developed during the 15 year term. If certain conditions are met, the Company has the option to deliver additional volumes and commit additional acreage to the new plant as production increases. The natural gas processing plant and gathering pipelines will be designed, built and operated by Targa. The plant is expected to be operational by early 2017.

Fifth Amendment to the Second Amended and Restated Credit Agreement

On October 30, 2015, the Company, the Guarantors, the Administrative Agent and the other agents and lenders party thereto entered into the Fifth Amendment to the Second Amended and Restated Credit Agreement, dated as of June 30, 2014, by and among the Company, the Guarantors, the Administrative Agent and the other agents and lenders party thereto.

The Fifth Amendment, among other things, (1) amended the Second Amended and Restated Credit Agreement and its exhibits and schedules to (a) update certain disclosures to be effective as of the date of the Fifth Amendment, including (i) the organizational chart and subsidiary list in the schedules to the Second Amended and Restated Credit Agreement to reflect the disposition of Catarina Midstream, LLC and (ii) the lists of marketing contracts and swap agreements in the schedules to the Second Amended and Restated Credit Agreement; (b) modify certain representations and the form of compliance certificate under the Second Amended and Restated Credit Agreement to reference updated disclosures provided to the Administrative Agent pursuant to the terms of the Second Amended and Restated Credit Agreement; (c) modify certain covenants to expressly (i) not require the Company to deliver fourth quarter financial statements prior to the delivery of annual financial statements, (ii) not require that certain insurance policies of the Loan Parties contain certain endorsements or loss payable provisions and (iii) permit the Loan Parties to enter into certain leases; (d) permit the Loan Parties to deliver certain financial statements and related documents required under the Second Amended and Restated Credit Agreement electronically and provide that, except in the case of compliance certificates or for other deliveries to the Administrative Agent or a lender that requests physical delivery, any such statements and documents that are filed with the SEC are deemed delivered when posted on the Company's website or other internet or intranet website to which each lender and the Administrative Agent have access; (e)(i) specifically identify TPL South Texas Processing Company LP as the counterparty to the previously permitted Eagle Ford Midstream JV Transaction (as defined in the Fifth Amendment), (ii) separately identify and permit the "Gathering JV" component of such transaction and increase from $80 million to $115 million the permitted investment basket for investments in the Eagle Ford Midstream JV Transaction generally, thereby making the entire existing $50 million "other" permitted investment basket available for investments either in such transaction or other investments in unrestricted subsidiaries of the Company and (iii) provide that none of the transactions comprising the Eagle Ford Midstream JV Transaction shall be considered synthetic leases; (f) modify the change-in-business covenant to permit unrestricted subsidiaries to make direct or indirect investments in the oil and gas industry and related businesses and activities without restrictions on geography; (g) change the definition of "Material Adverse Effect" to (i) reference, among other things, (x) the ability of the Loan Parties to perform their obligations under the Loan Documents (as defined in the Second Amended and Restated Credit Agreement), rather than the ability of any Loan Party to perform any of its obligations under any Loan Document, (y) the validity or enforceability of the Loan Documents, rather than the validity or enforceability of any Loan Document, (z) the rights and remedies of or benefits available to the Administrative Agent, any issuing bank or any lender under the Loan Documents, rather than under any Loan Document and (ii) provide that general market or industry conditions, which do not affect the Company in a disproportionately adverse manner, shall not constitute or be taken into account in determining whether there has been a "Material Adverse Effect"; and (h) provide for other technical amendments, clarifications and corrections; and (2) waived any existing breaches of, and any resulting defaults or events of defaults under the Second Amended and Restated Credit Agreement with respect to, the Company's covenants in the Second Amended and Restated Credit Agreement (a) to deliver fourth quarter financial statements within 45 days after the end of such fiscal quarter; (b) to provide certain loss payable clauses or provisions and endorsements with respect to certain insurance maintained by the Loan Parties; and (c) in respect of leases other than capital leases and leases of hydrocarbon interests.

Table of Contents

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 2014 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 207,000 net leasehold acres in the oil and condensate, or black oil and volatile oil, windows of the Eagle Ford Shale and approximately 66,000 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 95% of our 2015 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.

On June 30, 2014, we completed our Catarina acquisition of 106,000 net contiguous acres in Dimmit, LaSalle and Webb Counties, Texas with 176 gross producing wells 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 $557 million, comprised of the $639 million purchase price less approximately $82 million in normal and customary closing adjustments. Proved reserves as of the effective date were estimated to be approximately 60 mmboe and were 57 mmboe as of September 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 in the Catarina area are covered under lease acreage that is held by production, which acreage amounted to approximately 35,600 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 Catarina acquisition are subject to a continuous drilling obligation. Such drilling obligation requires us to drill (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. 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. In the third quarter of 2015 and during the current annual well commitment period, which commenced on July 1, 2015 and ends on June 30, 2016, the Company drilled 22 wells towards its 50 well annual commitment. Because it had exceeded its prior annual period's well commitment, the Company carried over 18 wells from the prior annual period to the current one. Therefore, to satisfy this year's annual well commitment of 50 wells, the Company must drill the remaining 10 wells before June 30, 2016, taking into account both the 22 wells drilled in the third quarter of 2015 and the 18 wells drilled in the prior annual period that the Company was permitted to carry over to the current period.

On March 31, 2015, we completed the Palmetto disposition consisting of the sale of escalating amounts of partial working interests in 59 wellbores located in Gonzales County, Texas for an adjusted purchase price of approximately $83.4 million. The effective date of the transaction was January 1, 2015. The aggregate average working interest percentage initially conveyed was 18.25% per wellbore and, upon January 1 of each subsequent year after the closing, the purchaser's working interest will automatically increase in incremental amounts according to the purchase agreement until January 1, 2019, at which point the purchaser will own a 47.5% working interest and we will own a 2.5% working interest in each of the wellbores. We received consideration consisting of approximately $83.0 million

Table of Contents

(approximately $81.4 million as adjusted) cash and 1,052,632 common units of SPP valued at approximately $2.0 million as of the date of closing.

Our 2015 capital budget of $550 600 million is allocated approximately 92% to the drilling of 87 net wells and completion of 109 net wells with the remainder allocated to facilities, leasing, and seismic activities.

For 2015, our operating plans largely focus on continued improvement to our manufacturing efficiency with the goal of steady improvement in our capital efficiency in order to preserve liquidity and financial flexibility. Our 2015 capital budget is focused on the development of our approximately 207,000 net acres in the Eagle Ford Shale. In the Eagle Ford, we plan to invest $485 $520 million, or approximately 95%, of our drilling and completion budget to spud 85 net wells and complete 107 net wells over the course of 2015. In addition, we expect to invest $25 $30 million in the TMS over the course of 2015 bringing online two gross (one net) wells.

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 207,000 net leasehold acres with an average working interest of approximately 92%. 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 plus up to 650 additional upper Eagle Ford Catarina locations, 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 nearly 3,300 potential gross (3,000 net) locations for potential future drilling. Consistent with other operators in this area, we perform multi stage hydraulic fracturing up to 38 stages on each well depending upon the length of the lateral section. For the year 2015, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In our Catarina area, we have approximately 106,000 net acres in Dimmit, LaSalle and Webb Counties, Texas with a 100% working interest. We anticipate drilling, completion and facilities costs on our acreage to be approximately

$4.2 million per well based on current well costs. We have brought 88 horizontal wells with combined average 30 day production rates of approximately 900 boe/d. For the year 2015, we plan to spend $390 $400 million to spud 73 and complete 86 net wells in our Catarina area.

In our Marquis area, we have approximately 43,000 net acres, the majority of which are in southwest Fayette and northeast Lavaca Counties, Texas with a 100% working interest. We have drilled 48 horizontal wells in our Prost area of Marquis that had average 30 day production rates of approximately 625 boe/d. We have drilled six horizontal wells in our Five Mile Creek area of Marquis that had average 30 day production rates of approximately 500 boe/d. We have identified up to 775 gross and net locations based on 60 acre well spacing for potential future drilling on our Marquis acreage. For the year 2015, we plan to spend $15 $20 million to spud one net well and complete three net wells in our Marquis area.

In our Cotulla area, we have approximately 50,000 net acres in Dimmit, Frio, LaSalle, Zavala, and McMullen Counties, Texas with an average working interest of approximately 88%. Our primary focus in our Cotulla area are our Alexander Ranch and Wycross development projects. In our Alexander Ranch development project, 45 wells have been brought online with average 30 day production rates of approximately 500 boe/d. In our Wycross development project, 38 wells have been brought online with average 30 day production rates of approximately 650 boe/d. We have identified up to 950 gross (850 net) locations based on 40 acre well spacing for potential future drilling on our Cotulla acreage. For the year 2015, we plan to spend $55 $65 million to spud eight net wells and complete 14 net wells in our Cotulla area.

In our Palmetto area, we have approximately 8,500 net acres in Gonzales County, Texas with a current average working interest of approximately 34% incorporating the recent divestiture of certain wellbores pursuant to the Palmetto disposition, which will decrease to approximately 11% by 2019 taking into account the decreasing working interests pursuant to the Palmetto disposition purchase agreement. The Company anticipates it will maintain an approximate 50%

working interest in conjunction with future development drilling in Palmetto. We have participated in the drilling of 78 gross wells on our acreage that had an average 30 day production rates of approximately 900 boe/d. We have identified up to 325 gross (155 net) locations based on 40 acre well spacing for potential future drilling on our Palmetto acreage. For the year 2015, we plan to spend $25 $35 million to spud three and complete four net wells in our Palmetto area.

TMS

In August 2013, we acquired rights to 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. In connection with the TMS transactions we established an AMI in the TMS with SR, which transaction included a carry on drilling costs for up to 6 gross (3 net) wells. As part of the transaction, we acquired all of our 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. As of September 30, 2015, the AMI held rights to approximately 143,000 gross (103,000 net) acres, of which we owned approximately 66,000 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 approximately $7.5 million at the time of the transaction. 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 the Initial Well Carry. In August 2015, the Company signed an agreement with SR whereby the Company paid SR approximately $8 million in lieu of drilling the remaining two Additional Wells. The Buyout Agreement stipulates that SN has earned full rights to all acreage stated in the TMS transaction and effectively terminates any future well carry commitments.

We plan to defer drilling on the gross Additional Wells originally planned for 2015. We do not anticipate that the plan for deferral will materially impact our ability to maintain our core acreage in the play under our leases.

Recent Developments

During the fourth quarter of 2014, oil prices began a substantial and rapid decline which has continued in 2015. In response to that decline, the Company initiated a series of financial and operational activities highlighted below. Our capital budget was substantially reduced, first in November 2014, again in January 2015, and then again in August 2015 to the current planned amount of $550 to $600 million.

Significant market and operational factors impacting our current results and future expectations include:

- the substantial and rapid decline in oil prices described above;

- the sustained decline in oil prices through the first nine months of 2015 and its impact on many of the metrics used to evaluate the Company, including revenue, Adjusted EBITDA (defined below), and operating cash flows. In the light of the current trend in market prices, historical figures may not be indicative of future expectations;

- the Company believes it can fully fund its capital spending plan for 2015 from cash on hand and internally generated cash flows, leaving the borrowing capacity under its Second Amended and Restated Credit Agreement unused while still being able to modestly increase production volumes year over year;

- the Company's borrowing base was re determined in April 2015 and meetings were held in October 2015 to re-determine the borrowing base. We are currently expecting our borrowing base to be reduced from $550 million to $500 million with no change to the elected commitment amount, but nothing has been agreed upon as of the date of this filing. The April re determination did not impact our aggregate elected commitment amount and we do not expect that any potential future changes to our borrowing base would impact our aggregate elected commitment amount or our ability to fund our anticipated activity;

Table of Contents

- our 2015 capital budget has been substantially reduced to a current planned amount of $550 to $600 million, as compared to actual capital expenditures in 2014 (excluding acquisition activity) of approximately $800 million;

- the 2015 capital budget remains subject to further adjustments, depending on market conditions, and the Company maintains significant flexibility in our operations to be able to increase or decrease our capital budget quickly to react to changes in market conditions;

- although always a focus of the Company, in the current environment, we have emphasized the strategy to enhance returns through operational and cost efficiencies throughout the Company, which has led to substantial cost savings across the Company's asset base;

- we still intend to evaluate and pursue strategic acquisitions that will benefit the Company through cost effective additions to Company's current and/or future operations and reserve base;

- we still intend to evaluate and pursue strategic asset sales that will benefit the Company through return of capital that can help facilitate the Company's ability to re invest funds from structured transactions into potentially higher returning drilling opportunities;

- our Catarina acquisition in 2014 has had a positive impact on our reserves and financial position, and the Company is now targeting three distinct vertical productive Eagle Ford zones at Catarina and believes that potential for stacked development exists in the Lower, Middle, and Upper Eagle Ford, which we expect to increase the upside of the acquisition in 2015 and beyond;

- in February 2015, the Company modified certain of its crude oil enhanced swap and three way collar transactions to create crude oil swaps on a costless transactional basis. The modification to a fixed price eliminates downside risk, preserves value and provides the Company with greater certainty in crude oil pricing for the remainder of 2015;

- on March 31, 2015, we completed the Palmetto disposition with an effective date of January 1, 2015 for an adjusted purchase price of approximately $83.4 million. After adjustments to the purchase price, we received cash consideration of approximately $81.4 million and common units of SPP valued at approximately $2 million. Subsequent to the quarter end, the Company contributed all of the common units of SPP (105,263 common units after a 1-for-10 reverse split completed by SPP on August 3, 2015) received in connection with the Palmetto disposition;

- under the Second Amended and Restated Credit Agreement, we have two financial covenants: (i) a current ratio test (current assets plus undrawn borrowing capacity under such agreement to current liabilities) of at least 1.0 to 1.0; and (ii) a senior secured debt to consolidated LTM EBITDA test of not greater than 2.25 to 1.0 as of the last day of any fiscal quarter;

·

in April 2015, the Company entered into NYMEX WTI puts to hedge 4.026 MBbls of 2016 production at $60 per Bbl. The puts are subject to deferred premium payments that will be paid to the counterparty with each monthly settlement beginning in January 2016. The puts allow the Company to hedge 4.026 MBbls of 2016 production at a floor of $60 without limiting upside if oil prices increase above $60 per Bbl;

- we have commodity derivative contracts in place covering approximately 50% of the mid point of our estimated total production for 2015;

- based on the expectation that the current decline in average prices will continue during 2015, we expect that the Company could incur additional non cash impairments to our full cost pool in 2015; and

- in October 2015, the Company completed the Western Catarina Midstream Divestiture for cash consideration of approximately $345 million, subject to normal and customary closing and post-closing adjustments.

Table of Contents

Outlook

Due to the uncertainty regarding future commodity prices, the Company plans to manage its operating activities and financial liquidity carefully. We expect to be able to fund the current 2015 capital program with cash on hand and operating cash flow. We believe the results of that capital program will allow us to modestly grow our total production of hydrocarbons over the levels we reported for 2014. We plan to continuously evaluate our level of operating activity in light of both actual commodity prices and changes we are able to make to our costs of operations and make further adjustments to our capital spending program as appropriate. In addition, we expect to continue to regularly review acquisition opportunities from third parties or other members of the Sanchez Group, and we intend to evaluate and pursue strategic asset sales that can help facilitate the Company's ability to re invest funds from structured transactions into potentially higher returning drilling opportunities.

The average oil price, WTI Cushing, used in the SEC pricing methodology for calculating the PV 10 and Standardized Measures and for performing impairment tests under the full cost method, calculated as the unweighted arithmetic average of the first day of the month price for each month within the 12 month period ended September 30, 2015 was $59.21 per barrel and the average natural gas price, at Henry Hub, and calculated in the same manner, was $3.06 per mmbtu. As of September 30, 2015, the SEC prices for oil and natural gas have decreased approximately 17% and 10%, respectively, from June 30, 2015. As of September 30, 2015, the SEC prices for oil and natural gas have decreased approximately 38% and 30%, respectively from December 31, 2014.

As a result of less favorable commodity prices adversely affecting proved reserve values and the current commodity prices impact on future drilling opportunities, we recorded a full cost ceiling test impairment after income taxes of $454.6 million and $1,365.0 million, respectively, for the three and nine months ended September 30, 2015. As a result of less favorable commodity prices adversely affecting proved reserve values and the historical costs to drill and complete wells carried as proved undeveloped, as compared to current drilling and completion costs, we recorded a full cost ceiling test impairment before income taxes of $213.8 million for the year ended December 31, 2014. Based on the sustained decline in average prices throughout the first nine months of 2015 and a current expectation that prices will remain unfavorable during the remainder of 2015 based upon the current NYMEX forward prices, absent a material addition to proved reserves and/or a material reduction in future development costs, there is a reasonable likelihood that the Company will incur additional impairments to our full cost pool in 2015.

Table of Contents

Results of Operations

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014

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 September 30,		Increase (Decrease) 2015 vs 2014	
	2015	2014	$	%
Net Production:				
Oil (mbo)	1,671	1,682	(11)	(1) %
Natural gas liquids (mbbl)	1,509	964	545	57 %
Natural gas (mmcf)	10,090	5,440	4,650	85 %
Total oil equivalent (mboe)	4,862	3,552	1,310	37 %
Average Sales Price Excluding Derivatives(1):				
Oil ($ per bo)	$ 41.61	$ 93.87	$ (52.26)	(56)%
Natural gas liquids ($ per bbl)	11.30	28.34	(17.04)	(60)%
Natural gas ($ per mcf)	2.77	4.07	(1.30)	(32)%
Oil equivalent ($ per boe)	$ 23.56	$ 58.37	$ (34.81)	(60)%
Average Sales Price Including Derivatives(2):				
Oil ($ per bo)	$ 62.25	$ 92.45	$ (30.20)	(33)%
Natural gas liquids ($ per bbl)	11.30	28.34	(17.04)	(60)%
Natural gas ($ per mcf)	3.26	4.14	(0.88)	(21)%
Oil equivalent ($ per boe)	$ 31.68	$ 57.81	$ (26.13)	(45)%
REVENUES(1):				
Oil sales	$ 69,532	$ 157,907	$ (88,375)	(56)%
Natural gas liquids sales	17,055	27,309	(10,254)	(38)%
Natural gas sales	27,939	22,134	5,805	26 %
Total revenues	$ 114,526	$ 207,350	$ (92,824)	(45)%

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

Table of Contents

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 September 30, 2015	2014
Production:		
Oil - mbo		
Catarina	837	343
Marquis	306	521
Cotulla	401	515
Palmetto	111	301
Other	16	2
Total	1,671	1,682
Natural gas liquids - mbbl		
Catarina	1,355	694
Marquis	42	78
Cotulla	87	126
Palmetto	25	66
Other	—	—
Total	1,509	964
Natural gas - mmcf		
Catarina	9,247	3,914
Marquis	186	321
Cotulla	507	821
Palmetto	148	380
Other	2	4
Total	10,090	5,440
Net production volumes:		
Total oil equivalent (mboe)	4,862	3,552
Average daily production (boe/d)	52,844	38,613

Net Production. Production increased from 3,552 mboe for the three months ended September 30, 2014 to 4,862 mboe for the three months ended September 30, 2015 due to our drilling program. As detailed in the following table, the Catarina acquisition added 2,044 mboe of production during the three months ended September 30, 2015. The number of gross wells producing at the period end and the production for the periods were as follows:

Three Months Ended
September 30,

	2015		2014	
	# Wells	mboe	# Wells	mboe
Catarina	264	3,733	185	1,689
Marquis	103	379	70	651
Cotulla	139	573	122	777
Palmetto	72	161	61	432
Other	14	16	5	3
Total	592	4,862	443	3,552

For the three months ended September 30, 2015, 34% of our production was oil, 31% was NGLs and 35% was natural gas compared to the three months ended September 30, 2014 production that was 47% oil, 27% NGLs and 26% natural gas. The change in production mix between the periods was due to the increased production from the Catarina wells and the higher proportion of NGL and natural gas production as compared to oil production from this area.

Revenues. Oil, NGL, and natural gas sales revenues totaled approximately $114.5 million and $207.4 million for the three months ended September 30, 2015 and 2014, respectively. Oil and NGL sales revenues for the three months ended September 30, 2015 decreased $88.4 million and $10.3 million, respectively, while natural gas sales revenues for

Table of Contents

the three months ended September 30, 2015 increased $5.8 million, as compared to the three months ended September 30, 2014.

The tables below provide an analysis of the impacts of changes in production volumes and average realized prices between the periods on our revenues from the quarter ended September 30, 2014 to the quarter ended September 30, 2015 (in thousands, except average sales price). The decrease in average realized prices from the quarter ended September 30, 2014 to the quarter ended September 30, 2015 can be attributed to both the significant decline in commodity prices and the increased percentage of NGL and natural gas production relative to oil production that comprises our total production mix.

	Q3 2015 Production Volume	Q3 2014 Production Volume	Production Volume Difference	Q3 2014 Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (mbo)	1,671	1,682	(11)	$ 93.87	$ (1,025)
Natural gas liquids (mbbl)	1,509	964	545	$ 28.34	$ 15,449
Natural gas (mmcf)	10,090	5,440	4,650	$ 4.07	$ 18,918
Total oil equivalent (mboe)	4,862	3,552	1,310	$ 58.37	$ 33,342

	Q3 2015 Average Sales Price	Q3 2014 Average Sales Price	Average Sales Price Difference	Q3 2015 Volume	Revenue Increase/(Decrease) due to Price
Oil (mbo)	$ 41.61	$ 93.87	$ (52.26)	1,671	$ (87,350)
Natural gas liquids (mbbl)	$ 11.30	$ 28.34	$ (17.04)	1,509	$ (25,703)
Natural gas (mmcf)	$ 2.77	$ 4.07	$ (1.30)	10,090	$ (13,113)
Total oil equivalent (mboe)	$ 23.56	$ 58.37	$ (34.81)	4,862	$ (126,166)

Additionally, a 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the three months ended September 30, 2015 by approximately $11.5 million.

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 September 30,		Increase (Decrease) 2015 vs 2014	
	2015	2014	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 40,345	$ 34,380	$ 5,965	17%
Production and ad valorem taxes	3,038	10,916	(7,878)	-72%
Depreciation, depletion, amortization and accretion	89,167	93,463	(4,296)	-5%
Impairment of oil and natural gas properties	454,628	—	454,628	
General and administrative (inclusive of stock-based compensation expense of $355 and $10, respectively, for the three months ended September 30, 2015 and 2014)	15,851	12,821	3,030	24%
Total operating costs and expenses	603,029	151,580	451,449	298%
Interest income and other income (expense)	(753)	82	(835)	*
Interest expense	(31,442)	(27,612)	(3,830)	14%
Net gains on commodity derivatives	103,996	47,416	56,580	119%
Income tax expense	158	26,625	(26,467)	-99%

* Not meaningful.

Table of Contents

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 17% to approximately $40.3 million for the three months ended September 30, 2015 as compared to $34.4 million for the same period in 2014. The increase in oil and natural gas production expenses in the third quarter of 2015 compared to the same period of 2014 is directly attributable to our increased production activities and well count on our existing acreage. Our average production expenses decreased from $9.68 per boe during the three months ended September 30, 2014 to $8.30 per boe for the three months ended September 30, 2015. This decrease was due primarily to increased efficiency in our overall operations between the periods. While we expect our oil and natural gas production expenses to increase as we add producing wells, we expect to continue our efficient operation of our properties. As discussed in Note 18, "Subsequent Events," the Company closed the Western Catarina Midstream Divestiture on October 14, 2015. In conjunction with the Western Catarina Midstream Divestiture, the Company entered into a long-term, fixed price gathering agreement with SPP, which we expect will increase our annual lease operating costs by approximately $2.0 per BOE.

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 $3.0 million and $10.9 million for the three months ended September 30, 2015 and 2014, respectively. The decrease in production and ad valorem taxes in the third quarter of 2015 compared to the same period in 2014 was due to the decrease in overall commodity price, and decrease in property value, between the periods. Our average production and ad valorem taxes decreased from $3.07 per boe during the three months ended September 30, 2014 to $0.62 per boe for the three months ended September 30, 2015. This decrease in rate is attributable to the lower applicable production tax rate in the Catarina area, in addition to the decreasing value of oil and natural gas properties causing a revision to our ad valorem estimates from third-party consultants. The lower production tax rate is the result of the characterization of the wells in the Catarina area as high cost gas wells, which apply a lower tax rate based on the market value of the gas produced. While this rate may vary depending on the actual capital costs incurred on a well by well basis, we expect the production tax rate to continue to be lower than the rates established in our other operating areas.

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 three months ended September 30, 2015 decreased $4.3 million to $89.2 million ($18.34 per boe) from $93.5 million ($26.31 per boe) for the three months ended September 30, 2014. The majority of the decrease in DD&A is related to the decrease in depletion rate due to full cost ceiling impairments recorded in the prior three quarters. In addition, estimated proved reserves as of September 30, 2015 were 18% lower than estimated proved reserves as of September 30, 2014. Higher production during the three months ended September 30, 2015 as compared to the same period in 2014 resulted in a $34.2 million increase in depletion expense and the decrease in the depletion rate resulted in a $38.8 million decrease in depletion expense. The remaining increase of $0.3 million in DD&A as compared to the three months ended September 30, 2014 is related to an increase in depreciation, amortization, and accretion between the periods presented.

Impairment of Oil and Natural Gas Properties. We utilize the full cost method of accounting to account for our oil and natural gas exploration and development activities. Under this method of accounting, we are required on a quarterly basis to determine whether the book value of our oil and natural gas properties (excluding unevaluated properties) is less than or equal to the “ceiling,” based upon the expected after tax present value (discounted at 10%) of the future net cash flows from our proved reserves. Any excess of the net book value of our oil and natural gas properties over the ceiling must be recognized as a non cash impairment expense. We recorded a full cost ceiling test impairment

Table of Contents

after income taxes of $454.6 million for the three months ended September 30, 2015. The impact of less favorable commodity prices adversely affecting proved reserve values was the main contributor to the ceiling impairment recorded at September 30, 2015. Changes in production rates, levels of reserves, future development costs, transfers of unevaluated properties, and other factors will determine our actual ceiling test calculation and impairment analyses in future periods. We recorded a full cost ceiling test impairment before income taxes of $213.8 million for the year ended December 31, 2014, and after income taxes of $441.5 million and $468.9 million for the three months ended March 31, 2015 and June 30, 2015, respectively. The combined impact of less favorable commodity prices adversely affecting proved reserve values and the historical costs to drill and complete wells carried as proved undeveloped, as compared to current drilling and completion costs, contributed to the ceiling impairment. Based on the expectation that the current decline in average prices will continue during 2015, the Company could incur additional non cash impairments to our full cost pool in 2015.

If the simple average of oil and natural gas prices as of the first day of each month for the trailing 12 month period ended September 30, 2015 had been $2.66 per Mmbtu for natural gas, $50.37 per Bbl of oil, and $20.10 per Bbl of propane, while all other factors remained constant, our ceiling test limitation related to the net book value of our proved oil and natural gas properties would have been reduced by approximately $282.5 million. The aforementioned prices were calculated based on a 12 month simple average, which includes the oil and natural gas prices on the first day of the month for the 10 months ended October 2015 and the October 2015 prices were held constant for the remaining two months. This reduction would have increased the impairment of our oil and natural gas properties pursuant to the ceiling test by approximately $282.5 million on a pro forma basis. The pro forma reduction in our ceiling test limitation is partially the result of a pro forma decrease in our proved reserves, which was primarily due to certain locations that would not be economical when using the pro forma prices. This calculation of the impact of lower commodity prices is prepared based on the presumption that all other inputs and assumptions are held constant with the exception of oil, natural gas, and NGL prices. Therefore, this calculation strictly isolates the impact of commodity prices on our ceiling test limitation and proved reserves. The impact of price is only a single variable in the estimation of our proved reserves and other factors noted above could have a significant impact on future reserves and the present value of future cash flows. There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in subsequent periods and this pro forma estimate should not be construed as indicative of our development plans or future results.

General and Administrative Expenses. Our general and administrative (“G&A”) expenses, including stock based compensation expense, totaled $15.9 million for the three months ended September 30, 2015 compared to $12.8 million for the same period in 2014. Excluding the stock based compensation, G&A expenses for the three months ended September 30, 2015 and 2014 were $15.5 million and $12.8 million, respectively. This increase was due primarily to additional costs for added personnel of SOG performing services for the Company and the increase in legal fees in connection with the Western Catarina Midstream Divestiture and Midstream Joint Venture transaction. Our G&A expenses, excluding stock based compensation expense, decreased from $3.61 per boe during the three months ended September 30, 2014 to $3.19 per boe for the three months ended September 30, 2015.

For the three months ended September 30, 2015 and 2014, we recorded non cash stock based compensation expense of approximately $355,000 and $10,000, respectively. The relatively insignificant expense amounts for both periods were caused by a decrease in the Company’s stock price during each respective quarter. This decrease in stock price was offset by an increase in awards outstanding and the associated amortization expense recognized. 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 decrease in stock price will cause a decrease to the stock based compensation expense recognized during the quarter.

Interest Expense. For the three months ended September 30, 2015, interest expense totaled $31.4 million and included $1.7 million in amortization of debt issuance costs. This is compared to the three months ended September 30, 2014, for which interest expense totaled $27.6 million and included $1.7 million in amortization of debt issuance costs. The interest expense incurred during the three months ended September 30, 2015 is primarily related to the 7.75% Notes issued in June and September 2013 and the 6.125% Notes issued in June and September 2014.

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 expense. During the three months ended September 30, 2015, we recognized a total gain of $104.0 million on our commodity derivative contracts primarily related to mark to market gains due to oil price decreases during the quarter.

The total net gain also included a net gain of $39.5 million associated with the settlements of commodity derivative contracts. These gains were primarily the result of the decreases in commodity prices from the time the deals were entered to the current period. During the three months ended September 30, 2014, we recognized a total gain of $47.4 million on our commodity derivative contracts primarily from decreases in commodity prices during the period. The total net gain also included a net loss of $2.0 million associated with the settlements of commodity derivative contracts.

Income Tax Expense. For the three months ended September 30, 2015, the Company recorded income tax expense of $158,000. Due to the full cost ceiling impairment recorded, the Company was in a net loss position for the quarter but had current income tax expense related to adjustments for immaterial differences from the 2014 income tax return filed in September 2015 to the accrual for 2014 income taxes recorded in December 2014. Our effective tax rate for the three months ended September 30, 2015 rounded to approximately 0% compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is related to a valuation allowance of approximately $141.5 million recorded during the period. For the three months ended September 30, 2014, income tax expense totaled $26.6 million. Our effective tax rate for the three months ended September 30, 2014 was 35.2%. 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 35.2% for the three months ended September 30, 2014 is primarily related to non-deductible general and administrative expenses recorded during the period.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014

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):

	Nine Months Ended September 30,		Increase (Decrease) 2015 vs 2014	
	2015	2014	$	%
Net Production:				
Oil (mbo)	5,372	4,257	1,115	26 %
Natural gas liquids (mbbl)	4,097	1,477	2,620	177 %
Natural gas (mmcf)	26,217	8,207	18,010	219 %
Total oil equivalent (mboe)	13,839	7,103	6,736	95 %
Average Sales Price Excluding Derivatives(1):				

Oil ($ per bo)	$ 45.53	$ 97.35	$ (51.82)	(53) %
Natural gas liquids ($ per bbl)	11.86	29.72	(17.86)	(60) %
Natural gas ($ per mcf)	2.79	4.29	(1.50)	(35) %
Oil equivalent ($ per boe)	$ 26.47	$ 69.49	$ (43.02)	(62) %
Average Sales Price Including Derivatives(2):				
Oil ($ per bo)	$ 61.15	$ 95.07	$ (33.92)	(36) %
Natural gas liquids ($ per bbl)	11.86	29.72	(17.86)	(60) %
Natural gas ($ per mcf)	3.29	4.25	(0.96)	(23) %
Oil equivalent ($ per boe)	$ 33.48	$ 68.08	$ (34.60)	(51) %
REVENUES(1):				
Oil sales	$ 244,554	$ 414,484	$ (169,930)	(41) %
Natural gas liquids sales	48,602	43,918	4,684	11 %
Natural gas sales	73,091	35,171	37,920	108 %
Total revenues	$ 366,247	$ 493,573	$ (127,326)	(26) %

(1) Excludes the realized impact of derivative instruments.

(2) Includes the realized impact of derivative instruments.

Table of Contents

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:

	Nine Months Ended September 30,	
	2015	2014
Production:		
Oil—mbo		
Catarina	2,235	343
Marquis	1,188	1,375
Cotulla	1,399	1,546
Palmetto	497	990
Other	53	3
Total	5,372	4,257
Natural gas liquids—mbbl		
Catarina	3,564	694
Marquis	166	182
Cotulla	256	390
Palmetto	111	211
Other	—	—
Total	4,097	1,477
Natural gas—mmcf		
Catarina	23,227	3,914
Marquis	684	693
Cotulla	1,663	2,447
Palmetto	620	1,147
Other	23	6
Total	26,217	8,207
Net production volumes:		
Total oil equivalent (mboe)	13,839	7,103
Average daily production (boe/d)	50,690	26,018

Net Production. Production increased from 7,103 mboe for the nine months ended September 30, 2014 to 13,839 mboe for the nine months ended September 30, 2015 due to our drilling program and acquisition activity. As detailed in the following table, the Catarina acquisition added 7,981 mboe of production during the nine months ended September 30, 2015. The number of gross wells producing at the period end and the production for the periods were as follows:

	Nine Months Ended September 30,			
	2015		2014	
		mboe		mboe

	# Wells		# Wells	
Catarina	264	9,670	185	1,689
Marquis	103	1,467	70	1,673
Cotulla	139	1,933	122	2,344
Palmetto	72	712	61	1,393
Other	14	57	5	4
Total	592	13,839	443	7,103

For the nine months ended September 30, 2015, 39% of our production was oil, 30% was NGLs and 31% was natural gas compared to the nine months ended September 30, 2014 production that was 60% oil, 21% NGLs and 19% natural gas. The change in production mix between the periods was due to the Catarina acquisition and the higher proportion of NGL and natural gas production as compared to oil production from this area.

Revenues. Oil, NGL, and natural gas sales revenues totaled approximately $366.2 million and $493.6 million for the nine months ended September 30, 2015 and 2014, respectively. Oil sales revenues for the nine months ended September 30, 2015 decreased $169.9 million, while NGL and natural gas sales revenues for the nine months ended September 30, 2015 increased $4.7 million and $37.9 million, respectively, as compared to the nine months ended September 30, 2014.

Table of Contents

The tables below provide an analysis of the impacts of changes in production volumes and average realized prices between the periods on our revenues from the nine months ended September 30, 2014 to the nine months ended September 30, 2015 (in thousands, except average sales price). The decrease in average realized prices from the nine months ended September 30, 2014 to the nine months ended September 30, 2015 can be attributed to both the significant decline in commodity prices and the increased percentage of NGL and natural gas production relative to oil production that comprises our total production mix.

	YTD Q3 2015 Production Volume	YTD Q3 2014 Production Volume	Production Volume Difference	YTD Q3 2014 Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (mbo)	5,372	4,257	1,115	$ 97.35	$ 108,479
Natural gas liquids (mbbl)	4,097	1,477	2,620	$ 29.72	$ 77,853
Natural gas (mmcf)	26,217	8,207	18,010	$ 4.29	$ 77,184
Total oil equivalent (mboe)	13,839	7,103	6,736	$ 69.49	$ 263,516

	YTD Q3 2015 Average Sales Price	YTD Q3 2014 Average Sales Price	Average Sales Price Difference	YTD Q3 2015 Volume	Revenue Increase/(Decrease) due to Price
Oil (mbo)	$ 45.53	$ 97.35	$ (51.82)	5,372	$ (278,409)
Natural gas liquids (mbbl)	$ 11.86	$ 29.72	$ (17.86)	4,097	$ (73,169)
Natural gas (mmcf)	$ 2.79	$ 4.29	$ (1.50)	26,217	$ (39,264)
Total oil equivalent (mboe)	$ 26.47	$ 69.49	$ (43.02)	13,839	$ (390,842)

Additionally, a 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the nine months ended September 30, 2015 by approximately $36.6 million.

Operating Costs and Expenses

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

	Nine Months Ended September 30,		Increase (Decrease) 2015 vs 2014	
	2015	2014	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 110,166	$ 64,203	$ 45,963	72%
Production and ad valorem taxes	20,011	29,161	(9,150)	-31%
Depreciation, depletion, amortization and accretion	296,541	225,297	71,244	32%
Impairment of oil and natural gas properties	1,365,000	—	1,365,000	*
General and administrative (inclusive of stock-based compensation expense of $15,924 and $25,888, respectively, for the nine months ended September 30, 2015 and 2014)	59,290	60,999	(1,709)	-3%
Total operating costs and expenses	1,851,008	379,660	1,471,348	388%
Interest income and other income (expense)	(1,804)	97	(1,901)	*
Interest expense	(94,500)	(58,145)	(36,355)	63%
Net gains on commodity derivatives	111,550	6,399	105,151	*
Income tax expense	7,600	21,946	(14,346)	-65%

*Not meaningful.

Oil and Natural Gas Production Expenses. Our oil and natural gas production expenses increased 72% to approximately $110.2 million for the nine months ended September 30, 2015 as compared to $64.2 million for the same period in 2014. The increase in oil and natural gas production expenses in the nine months ended September, 30 2015 compared to the same period of 2014 is directly attributable to our increased production activities and well count in the Eagle Ford Shale, as a result of the Catarina acquisition completed during 2014, as well as drilling activities on our existing acreage. Our average production expenses decreased from $9.04 per boe during the nine months ended September 30, 2014 to $7.96 per boe for the nine months ended September 30, 2015. This decrease was due primarily to increased efficiency in our overall operations and increase in production between the periods. While we expect our oil and natural gas production expenses to increase as we add producing wells, we expect to continue our efficient operation of our properties, and do not expect significant increases in our average production expenses per boe from normal drilling activities.

Production and Ad Valorem Taxes. Our production and ad valorem taxes totaled $20.0 million and $29.2 million for the nine months ended September 30, 2015 and 2014, respectively. For a discussion of our Production and Ad Valorem taxes, see "—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Operating Costs and Expenses—Production and Ad Valorem Taxes." Our average production and ad valorem taxes decreased from $4.11 per boe during the nine months ended September 30, 2014 to $1.45 per boe for the nine months ended September 30, 2015.

Depreciation, Depletion, Amortization and Accretion. Our DD&A expense for the nine months ended September 30, 2015 increased $71.2 million to $296.5 million from $225.3 million for the nine months ended September 30, 2014. However, our DD&A expense per boe for the nine months ended September 30, 2015 ($21.43 per boe) decreased approximately 32% from the nine months ended September 30, 2014 ($31.72 per boe), due to a decrease in the depletion rate from the accumulated ceiling impairments recorded during 2014 and 2015. For a discussion of our DD&A expense, see "—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Operating Costs and Expenses—Depreciation, Depletion, Amortization, and Accretion."

Impairment of Oil and Natural Gas Properties. We recorded a full cost ceiling test impairment after income taxes of $1,365.0 million for the nine months ended September 30, 2015. For a discussion of our impairment of oil and natural gas properties expense, see "—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Operating Costs and Expenses—Impairment of Oil and Natural Gas Properties."

General and Administrative Expenses. Our G&A expenses, including stock based compensation expense, totaled $59.3 million for the nine months ended September 30, 2015 compared to $61.0 million for the same period in 2014. Excluding the stock based compensation, G&A expenses for the nine months ended September 30, 2015 and 2014 were $43.4 million and $35.1 million, respectively. This increase was due primarily to additional costs for added personnel of SOG performing services for the Company and the increase in legal fees in connection with the Western Catarina Midstream Divestiture and Midstream Joint Venture transaction during the nine-month period ended September 30, 2015. Our G&A expenses, excluding stock based compensation expense, decreased from $4.94 per boe during the nine months ended September 30, 2014 to $3.13 per boe for the nine months ended September 30, 2015.

For the nine months ended September 30, 2015 and 2014, we recorded non cash stock based compensation expense of approximately $15.9 million and $25.9 million, respectively. For a discussion of our general and administrative expense, see "—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Operating Costs and Expenses—General and Administrative Expenses."

Interest Expense. For the nine months ended September 30, 2015, interest expense totaled $94.5 million and included $5.3 million in amortization of debt issuance costs. This is compared to the nine months ended September 30, 2014, for which interest expense totaled $58.1 million and included $7.2 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. The interest expense incurred during the nine months ended September 30, 2015 is primarily related to the 7.75% Notes issued in June and September 2013 and the 6.125% Notes issued in June and September 2014.

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

Table of Contents

and expense. During the nine months ended September 30, 2015, we recognized a total gain of $111.6 million on our commodity derivative contracts which included a net gain of $97.0 million associated with the settlements of commodity derivative contracts. For a discussion of our commodity derivate transactions, see "—Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014—Operating Costs and Expenses—Commodity Derivative Transactions." During the nine months ended September 30, 2014, we recognized a total gain of $6.4 million on our commodity derivative contracts which included a net loss of $10.0 million associated with the settlements of commodity derivative contracts. These losses were primarily the result of increases in commodity prices during the period.

Income Tax Expense. For the nine months ended September 30, 2015, the Company recorded income tax expense of $7.6 million. Our effective tax rate for the nine months ended September 30, 2015 was (0.5)% compared to a statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is primarily related to a valuation allowance of approximately $519.2 million recorded during the period. For the nine months ended September 30, 2014, income tax expense totaled $21.9 million. Our effective tax rate for the nine months ended September 30, 2014 was 35.2% 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.

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 September 30, 2015, our critical accounting policies were consistent with those discussed in our 2014 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 depletion and impairment of oil and natural gas properties, 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.

Liquidity and Capital Resources

As of September 30, 2015, we had approximately $197 million in cash and cash equivalents and a $550 million borrowing base (with a $300 million aggregate elected commitment amount) under our revolving credit facility with a group of sixteen participating banks, resulting in available liquidity of approximately $497 million, not including the additional $250 million of approved revolving credit facility borrowing base, which we elected not to accept at this time, but which may be utilized subject to the satisfaction of certain conditions, including the consent of any lenders whose commitment is increased.

We expect to use a portion of our cash on hand and our internally generated cash flows from operations to fund our remaining 2015 capital expenditures. The Company believes it can fully fund its capital spending plan from cash on hand and internally generated cash flows, leaving the borrowing capacity under our Second Amended and Restated Credit Agreement unused in 2015, while still being able to modestly increase production volumes year over year. However, we believe that we have significant flexibility with respect to our financing alternatives, including, equity and debt offerings, and may, depending on market conditions, consider such alternative sources of capital. We may from time to time seek to retire or purchase our outstanding debt through cash purchases and/or exchanges for equity

Table of Contents

securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

For a description of current and previous credit agreements along with the indenture 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 13, "Stockholders' Equity."

Cash Flows

Our cash flows for the nine months ended September 30, 2015 and 2014 (in thousands) are as follows:

	Nine Months Ended September 30,	
	2015	2014
Cash Flow Data:		
Net cash provided by operating activities	$ 225,150	$ 272,680
Net cash used in investing activities	$ (489,608)	$ (1,099,994)
Net cash provided by (used in) financing activities	$ (12,372)	$ 1,270,055

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $225.2 million for the nine months ended September 30, 2015 compared to $272.7 million for the same period in 2014. This decrease was related to the unfavorable impact of changes in working capital items, including lower revenues due to the impact of lower average commodity prices partially offset by higher sales volumes between these periods and cash settlements received on commodity derivative contracts.

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 $489.6 for the nine months ended September 30, 2015 compared to $1.1 billion for the same period in 2014. Capital expenditures for leasehold and drilling activities for the nine months ended September 30, 2015 totaled $561.8 million, primarily associated with bringing online 107 gross wells. In connection with the Palmetto disposition on March 31, 2015, we received cash consideration of approximately $81.4 million. In connection with the Buyout Agreement in August 2015, we spent approximately $8 million. In addition, we invested $1.9 million in other property and equipment. For the nine months ended September 30, 2014, we incurred capital expenditures of $532.3 million, primarily associated with bringing online 79 gross wells. We paid cash of $559.3 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 $9.6 million in other property and equipment.

Net Cash Provided by (Used in) Financing Activities. Net cash flows used in financing activities totaled an outflow of $12.4 million for the nine months ended September 30, 2015 compared to an inflow of $1.3 billion for the same period in 2014. During the nine months ended September 30, 2015, we made payments of $12.0 million for dividends on our Series A Preferred Stock and Series B Preferred Stock.

During the nine months ended September 30, 2014, we received net proceeds from the issuance of common stock of $167.5 million, after deducting offering costs payable by us of $8.7 million. We also made payments of $12.3 million for dividends on our Series A Preferred Stock and Series B Preferred Stock. We received net proceeds of approximately $1.12 billion from the issuance of our Original 6.125% Notes, consisting of gross proceeds of $1.15 billion and debt issuance costs of $20.9 million. Other debt issuance costs for the nine months ended September 30, 2014 totaled $10.0 million. On May 12, 2014, the Company borrowed $100 million under the Amended and Restated Credit Agreement. The Company used proceeds from the issuance of the Original 6.125% Notes to repay the $100 million

Table of Contents

outstanding under the Amended and Restated Credit Agreement, in addition to funding a portion of the purchase price of the Catarina acquisition.

Off Balance Sheet Arrangements

As of September 30, 2015, we did not have any off balance sheet arrangements.

Commitments and Contractual Obligations

Refer to Note 16, "Commitments and Contingencies" for a description of lawsuits pending against the Company.

As of September 30, 2015, our contractual obligations included our Senior Notes, interest expense on our Senior Notes, asset retirement obligations, rent expense for our corporate offices and other long term lease payments. There have been no material changes in our contractual obligations during the nine months ended September 30, 2015. The following table summarizes our contractual obligations as of September 30, 2015 (in thousands):

	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years	Total
Senior Notes	$ —	$ —	$ —	$ 1,750,000	$ 1,750,000
Interest expense (1)	116,938	233,875	233,875	222,593	807,281
Asset retirement obligations (2)	—	—	—	30,943	30,943
Office rent (3)	5,112	10,469	10,811	25,679	52,071
Other leases (4)	1,791	3,583	3,583	4,923	13,880
Total	$ 123,841	$ 247,927	$ 248,269	$ 2,034,138	$ 2,654,175

(1) Represents estimated interest payments that will be due under the $600 million 7.75% Notes and $1,150 million 6.125% Notes that will mature on June 15, 2021 and January 15, 2023, respectively.

(2) 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 10, "Asset Retirement Obligations."

(3) Represents payments due for leasing corporate office space in Houston, Texas. The lease began on November 1, 2014 and continues through March 31, 2025.

(4) Represents payments due for a ground lease agreement for land owned by the Calhoun Port Authority which commenced on August 25, 2014 and continues until August 25, 2024. Also represents payments due for an acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas which commenced on March 1, 2014 and continues through February 28, 2024.

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. Such drilling obligation requires us to drill (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. 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.

The Company’s ground lease with the Calhoun Port Authority is terminable upon 180 days written notice by the Company to the lessor in addition to a $1 million termination payment. In connection with the lease agreement for acreage in Kenedy County, Texas, there is a contractual requirement for the Company to spend a minimum of $4 million to make permanent improvements over the ten year life of the lease. The lease agreement does not specify the timing for

Table of Contents

such improvements to be made within the lease term. The Company has the right to terminate its lease obligation at any time without penalty with nine months advanced written notice and payment of any accrued leasehold expenses.

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 received (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:

· Premiums on commodity derivative contracts;

· 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 (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.

Table of Contents

The following table presents a reconciliation of our net income (loss) to Adjusted EBITDA (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$ (416,860)	$ 49,031	$ (1,477,115)	$ 40,318
Plus:				
Interest expense	31,442	27,612	94,500	58,145
Net gains on commodity derivative contracts	(103,996)	(47,416)	(111,550)	(6,399)
Net settlements received (paid) on commodity derivative contracts	39,488	(1,635)	96,981	(9,652)
Depreciation, depletion, amortization and accretion	89,167	93,463	296,541	225,297
Impairment of oil and natural gas properties	454,628	—	1,365,000	—
Stock-based compensation expense	355	10	15,924	25,888
Acquisition costs included in general and administrative	—	916	—	1,806
Write off of joint venture receivable, non-recurring	—	—	2,251	—
Income tax expense	158	26,625	7,600	21,946
Less:				
Premiums on commodity derivative contracts(1)	—	(359)	—	(359)
Interest income	(65)	(58)	(249)	(73)
Adjusted EBITDA	$ 94,317	$ 148,189	$ 289,883	$ 356,917

(1) This amount includes premiums accrued but not paid as of the end of the period.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net cash provided by operating activities	$ 79,234	$ 130,645	$ 228,638	$ 272,680
Net change in operating assets and liabilities	(17,033)	(10,856)	(33,589)	32,346
Cash reimbursements received for operating leasehold improvements	(2,650)	—	(2,650)	—
Interest expense, net (1)	29,470	25,642	88,395	50,203
Settlements on commodity derivative contracts, non-cash	6,034	1,842	7,544	(118)
Income tax expense	158	—	158	

Write off of joint venture receivable, non-cash	—	—	2,251	—
Acquisition costs included in general and administrative	—	916	—	1,806
Loss on investment in SPP	(896)	—	(864)	—
Adjusted EBITDA	$ 94,317	$ 148,189	$ 289,883	$ 356,917

(1) This amount includes cash interest expense on our Senior Notes and credit agreements, net of interest income.

Table of Contents

Adjusted Net Income

We present adjusted net income (loss) attributable to common stockholders ("Adjusted Net Income (Loss)") 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 the items included in our definition of Adjusted Net Income (Loss) below 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 (Loss) as net income (loss):

Plus:

· Non cash preferred stock dividends associated with conversion;

· Net losses (gains) on commodity derivative contracts;

· Net settlements received (paid) on commodity derivative contracts;

· Stock based compensation expense;

· Acquisition costs included in general and administrative;

· Impairment of oil and natural gas properties;

· Other non recurring items that we deem appropriate; and

· Tax impact of adjustments to net income (loss).

Less:

· Premiums on commodity derivative contracts;

· Preferred stock dividends; and

· Other non recurring items that we deem appropriate.

Table of Contents

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$ (416,860)	$ 49,031	$ (1,477,115)	$ 40,318
Less: Preferred stock dividends	(3,991)	(4,274)	(11,973)	(29,599)
Net income (loss) attributable to common shares and participating securities	(420,851)	44,757	(1,489,088)	10,719
Plus:				
Non-cash preferred stock dividends associated with conversion	—	284	—	17,297
Non-cash write off of joint venture receivables	—	—	2,251	—
Net gains on commodity derivatives contracts	(103,996)	(47,416)	(111,550)	(6,399)
Net settlements received (paid) on commodity derivative contracts	39,488	(1,635)	96,981	(9,652)
Premiums on commodity derivative contracts	—	(359)	—	(359)
Impairment of oil and natural gas properties	454,628	—	1,365,000	—
Stock-based compensation expense	355	10	15,924	25,888
Acquisition costs included in general and administrative	—	916	—	1,806
Tax impact of adjustments to net income (loss) (1)	2,020	16,905	12,470	(3,978)
Adjusted net income (loss)	(28,356)	13,462	(108,012)	35,322
Adjusted net income allocable to participating securities(2)	—	(622)	—	(1,630)
Adjusted net income (loss) attributable to common stockholders	$ (28,356)	$ 12,840	$ (108,012)	$ 33,692
Adjusted net income (loss) per common share - basic and diluted(3)(4)	$ (0.49)	$ 0.23	$ (1.89)	$ 0.66
Weighted average number of unrestricted outstanding common shares to calculate adjusted net income (loss) per common share - basic and diluted	57,426	55,732	57,141	51,153

(1) The tax impact is computed by utilizing the Company’s effective tax rate on the adjustments to reconcile net income (loss) to adjusted net income (loss).

(2) The Company’s restricted shares of common stock are participating securities.

(3) The three and nine months ended September 30, 2015 excludes 597,910 and 2,663,010 shares of weighted average restricted stock and 12,530,695 shares of common stock resulting from an assumed conversion of the Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted adjusted net loss per common share as these shares were anti dilutive.

(4) The three and nine months ended September 30, 2014 excludes 863,412 and 1,290,637 shares of weighted average restricted stock and 12,607,521 and 13,863,738 shares of common stock resulting from an assumed conversion of the Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted adjusted net income per common share as these shares were anti dilutive.

Adjusted Net Income (Loss) 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 (used in) operating activities or any other measure of financial performance or liquidity presented in accordance with U.S. GAAP.

Table of Contents

Pro Forma net income (loss) and Pro forma Adjusted EBITDA

We present pro forma net income (loss) and pro forma adjusted EBITDA attributable to common stockholders ("pro forma Adjusted EBITDA") in addition to our reported net income (loss) in accordance with U.S. GAAP and historical Adjusted EBITDA. Pro forma net income and pro forma Adjusted EBITDA are non GAAP financial measures that are used as supplemental financial measures by our management and by external users of our financial statements, such as investors, commercial banks and others, to assess our operating performance after giving effect to our recent significant acquisitions as compared to that of other companies in our industry, without regard to financing methods, capital structure or historical costs basis. They are also used to assess our ability to incur and service debt and fund capital expenditures. We define pro forma net income (loss) as net income (loss) plus adjustments to give effect to the acquisitions and related financing transactions identified in Note 3, "Acquisitions and Divestitures," which impacted the following accounts in our statement of operations:

- Total revenues (inclusive of oil sales, natural gas liquid sales and natural gas sales);
- Oil and natural gas production expenses;
- Production and ad valorem taxes;
- Depreciation, depletion, amortization and accretion;
- Impairment of oil and natural gas properties;
- Interest expense; and
- Income tax expense (benefit).

We define pro forma Adjusted EBITDA as pro forma net income (loss):

Plus:

- Pro forma interest expense, including net losses (gains) on interest rate derivative contracts;

- Net losses (gains) on commodity derivative contracts;
- Net settlements received (paid) on commodity derivative contracts;
- Pro forma depreciation, depletion, amortization and accretion;
- Stock based compensation expense;
- Acquisition costs included in general and administrative;
- Pro forma income tax expense (benefit);
- Loss (gain) on sale of oil and natural gas properties;
- Pro forma impairment of oil and natural gas properties; and
- Other non recurring items that we deem appropriate.

Less:

- Premiums on commodity derivative contracts;
- Interest income; and
- Other non recurring items that we deem appropriate.

Table of Contents

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

The following unaudited pro forma combined results for the periods presented below 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 Palmetto disposition had occurred on January 1, 2014. The following table presents a reconciliation of our net income to pro forma net income and pro forma Adjusted EBITDA (in thousands):

	Twelve Months Ended September 30, 2015	Nine Months Ended September 30, 2015	2014	Year Ended December 31, 2014
Net income (loss)	$ (1,539,224)	$ (1,477,115)	$ 40,318	$ (21,791)
Total revenues (a)	(10,175)	(3,243)	121,005	114,073
Oil and natural gas production expenses (b)	1,763	753	(40,088)	(39,078)
Production and ad valorem taxes (c)	821	339	(1,869)	(1,387)
Depreciation, depletion, amortization and accretion (d)	10,084	2,054	(47,232)	(39,202)
Impairment of oil and natural gas properties (e)	51,802	44,633	—	7,169
Interest expense (f)	—	—	(16,735)	(16,735)
Income tax benefit (expense) (g)	(3,182)	231	(5,277)	(8,690)
Pro forma net income (loss)	(1,488,112)	(1,432,348)	50,123	(5,641)
Plus:				
Pro forma interest expense (h)	126,155	94,500	74,880	106,535
Net gains on commodity derivative contracts (i)	(242,356)	(111,550)	(6,399)	(137,205)
Net settlements received (paid) on commodity derivative contracts (i)	112,234	96,981	(9,652)	5,600
Pro forma depreciation, depletion, amortization and accretion (j)	399,096	294,326	272,529	377,299
Pro forma impairment of oil and natural gas properties (k)	1,524,958	1,318,306	—	206,652
Stock-based compensation expense (i)	2,880	15,925	25,888	12,843
Acquisition costs included in general and administrative (i)	2	—	1,806	1,808
Pro forma income tax expense (benefit) (l)	(22,591)	7,371	27,223	(2,739)
Less:				

Premiums on commodity derivative contracts (i)(m)	(359)	—	(359)	(718)
Interest income (i)	(369)	(249)	(73)	(193)
Pro forma Adjusted EBITDA	$ 411,537	$ 283,262	$ 435,965	$ 564,241

(a) Represents the changes in oil, natural gas liquids and natural gas sales resulting from the Catarina acquisition and Palmetto disposition completed during 2014 and 2015.

(b) Represents the changes in oil and natural gas production expenses resulting from the Catarina acquisition and Palmetto disposition completed during 2014 and 2015.

(c) Represents the changes in production taxes resulting from the Catarina acquisition and Palmetto disposition completed during 2014 and 2015.

(d) Represents the changes in depreciation, depletion, amortization and accretion resulting from the Catarina acquisition and Palmetto disposition completed during 2014 and 2015.

(e) Represents the changes in impairment of oil and natural gas properties resulting from the Catarina acquisition and Palmetto disposition completed during 2014 and 2015.

(f) Represents the pro forma interest expense and amortization of debt issuance costs related to the issuance of the Original 6.125% Notes to fund the Catarina acquisition completed in June 2014.

Table of Contents

(g) Represents the incremental income tax expense related to the pro forma effects of combining the Company's operations with the Catarina and Palmetto assets' operations.

(h) Represents historical interest expense of $94,500, $58,145, $126,155, and $89,800 for the nine months ended September 30, 2015 and 2014, and the twelve months ended September 30, 2015 and December 31, 2014, respectively, combined with pro forma adjustments to interest expense (as described in footnote f above) for each respective period.

(i)Represents amounts as reported in the Company's historical statements of operations.

(j) Represents historical depreciation, depletion, amortization and accretion of $296,541, $225,297, $409,341, and $338,097 for the nine months ended September 30, 2015 and 2014, and the twelve months ended September 30, 2015 and December 31, 2014, respectively, combined with pro forma adjustments to depreciation, depletion, amortization and accretion (as described in footnotes d above) for each respective period.

(k) Represents historical impairment of oil and natural gas properties of $1,365,000, $0, $1,578,822, and $213,821 for the nine months ended September 30, 2015 and 2014, and the twelve months ended September 30, 2015 and December 31, 2014, respectively, combined with pro forma adjustments to impairment of oil and natural gas properties (as described in footnote e above) for each respective period.

(l) Represents historical income tax expense (benefit) of $7,600, $21,946, ($25,775) and ($11,429) for the nine months ended September 30, 2015 and 2014, and the twelve months ended September 30, 2015 and December 31, 2014, respectively, combined with pro forma adjustments to income tax expense (as described in footnote g above) for each respective period.

(m) This amount includes premiums accrued but not paid as of the end of the period.

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 oil, NGL and natural gas 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 relative strength of the global economy and the actions of the Organization of Petroleum Exporting Countries.

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 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. The Company further uses enhanced swaps for a portion of its commodity price hedging activities. An enhanced swap is a product created by simultaneously selling an out of the

Table of Contents

money put and using the premium value from the sale to modify or “enhance” the value of a swap executed at the same time. The transaction provides an absolute minimum price at the enhanced swap strike price until the put strike price level is reached at which point the Company receives the market price plus the difference between the enhanced swap price and the put strike price. 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. Please refer to Note 7, “Derivative Instruments” for a description of all of the Company’s derivatives covering anticipated future production as of September 30, 2015.

At September 30, 2015, the fair value of our commodity derivative contracts was a net asset of approximately $162.4 million. A 10% increase in the oil and natural gas index prices above the September 30, 2015 prices would result in a decrease in the fair value of our commodity derivative contracts of $36.4 million; conversely, a 10% decrease in the oil index price would result in an increase of $39.3 million.

Interest Rate Risk

As of September 30, 2015, no amounts were outstanding under our Second Amended and Restated 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 September 30, 2015. Our 6.125% Notes bear a fixed interest rate of 6.125% with an expected maturity date of January 15, 2023, and we had $1.15 billion outstanding as of September 30, 2015. 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 Securities Exchange Act of 1934, as amended (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.

The Company identified a material weakness during the year ended December 31, 2014, as described in our 2014 Annual Report. The Company took measures to remediate the material weakness during the three months ended March 31, 2015, which included the following actions:

(i) required meetings at the end of the quarter that included accounting, operations, and reserves engineering personnel to communicate the current drilling status, future drilling plans, and current estimated future development costs by development area; and

(ii) enhanced the detail of review procedures on the future development costs in the reserve report during the financial statement close process by comparing estimated future development costs to costs incurred at the well level detail.

Management believes that the measures described above have remediated the material weakness identified in our 2014 Annual Report.

Changes in Internal Controls

There was no change in our internal control over financial reporting during the three months ended September 30, 2015 that materially affected, or is reasonably likely to materially affect our internal control over financial reporting.

Table of Contents

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a description of our material pending legal proceedings, please refer to Note 16, "Commitments and Contingencies."

Item 1A. Risk Factors

Consider carefully the risk factors under the caption "Risk Factors" under Part I, Item 1A in our 2014 Annual Report, and under "Part II, Item 1A. Risk Factors" in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2014 Annual Report; and in our other public filings, press releases, and public discussions with our management.

If commodity prices continue to drop, we may be limited or unable to lawfully declare and pay dividends on our capital stock.

The Delaware General Corporation Law (the "DGCL") permits payment of dividends out of a corporation's surplus. Surplus is defined as the excess of net assets (total assets less total liabilities) over a corporation's capital as determined under the DGCL. If commodity prices continue to decline, the value of our net assets will also continue to decline and, accordingly, our ability to lawfully declare and pay dividends may also decline.

We adopted the Rights Plan, which though it was designed to preserve the value of our NOLs, may discourage the acquisition and sale of large blocks of our common stock and may result in significant dilution for certain stockholders.

The Rights Plan is designed to preserve stockholder value and the value of our NOLs by acting as a deterrent to any person acquiring beneficial ownership of 4.9% or more of the Company's outstanding common stock without the approval of the Board. The Rights Plan may discourage existing 5% common stockholders from selling their interest in a single block, which may impact the liquidity of the Company's common stock, may deter institutional investors from investing in our common stock, and may deter potential acquirers from making premium offers to acquire the Company, factors which may depress the market price of our common stock.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

None.

Table of Contents

Item 6. Exhibits

EXHIBIT INDEX

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

2.1	*	Purchase and Sale Agreement, dated September 25, 2015, by and among Sanchez Energy Corporation, SN Catarina, LLC and Sanchez Production Partners LP. (Incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K dated September 29, 2015).
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		Certificate of Designations of Series C Junior Participating Preferred Stock of Sanchez Energy Corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on July 29, 2015, and incorporated herein by reference).
3.4		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		Rights Plan dated as of July 28, 2015 between Sanchez Energy Corporation and Continental Stock Transfer & Trust Company, as Rights Agent (including the form of Certificate of Designations of Series C Junior Participating Preferred Stock attached thereto as Exhibit A, the form of Right Certificate attached thereto as Exhibit B and the Summary of Rights attached thereto as Exhibit C) (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 29, 2015, and incorporated herein by reference).
10.1	(a)	Third Amendment to Second Amended and Restated Credit Agreement, dated as of July 20, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto.
10.2	(a)	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of September 29, 2015, by and among Sanchez Energy Corporation, as borrower, SN Marquis LLC, SN Cotulla Assets LLC, SN Operating LLC, SN TMS, LLC, and SN Catarina LLC, as guarantors, Royal Bank of Canada, as administrative agent, and the other agents and lenders party thereto.
10.3		

Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of October 30, 2015, by and 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 guarantors, Royal Bank of Canada, as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 4, 2015, 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	(a)	—	XBRL Instance Document.
101.SCH	(a)	—	XBRL Taxonomy Extension Schema Document.
101.CAL	(a)	—	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	(a)	—	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	(a)	—	XBRL Taxonomy Extension Labels Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

* The exhibits and schedules to the Purchase and Sale 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 Securities and Exchange Commission upon request. Descriptions of such exhibits and schedules are set forth on page iii of the Purchase and Sale Agreement.

Table of Contents

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 November 9, 2015.

SANCHEZ ENERGY CORPORATION

By: /s/ G. Gleeson Van Riet
G. Gleeson Van Riet
Senior Vice President and Chief Financial Officer