Sanchez Energy Corp
Form 10-Q
August 08, 2016
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10 Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2016
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

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 August 5, 2016: 65,940,236

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Sanchez Energy Corporation

Form 10 Q

For the Quarterly Period Ended June 30, 2016

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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 utilize the services, personnel and other assets of Sanchez Oil & Gas Corporation (“SOG”) pursuant to existing services agreements;
- 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 realized benefits of our joint ventures, including with respect to our joint ventures with Targa Resources Corp. (“Targa”);
- the realized benefits of our transactions with Sanchez Production Partners LP (“SPP”), including with respect to the Palmetto escalating working interest sale, divestiture of Western Catarina midstream assets and the Carnero

Gathering Transaction referred to herein;

- 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;
- the credit worthiness and performance of our counterparts, including financial institutions, operating partners and other parties;

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- 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;

- 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 ("OPEC") 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.

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PART I—FINANCIAL INFORMATION

Item 1. Unaudited Financial Statements

Sanchez Energy Corporation

Condensed Consolidated Balance Sheets (Unaudited)

(in thousands, except par value and share amounts)

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$ 324,399	$ 435,048
Oil and natural gas receivables	39,191	30,668
Joint interest billings receivables	703	1,259
Accounts receivable - related entities	3,206	3,697
Fair value of derivative instruments	54,266	172,494
Other current assets	16,930	23,452
Total current assets	438,695	666,618
Oil and natural gas properties, at cost, using the full cost method:		
Proved oil and natural gas properties	3,071,240	2,914,867
Unproved oil and natural gas properties	247,505	253,529
Total oil and natural gas properties	3,318,745	3,168,396
Less: Accumulated depreciation, depletion, amortization and impairment	(2,610,137)	(2,412,293)
Total oil and natural gas properties, net	708,608	756,103
Other assets:		
Fair value of derivative instruments	201	5,789
Investments	70,629	49,985
Other assets	22,404	22,809
Total assets	$ 1,240,537	$ 1,501,304
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 2,937	$ 4,184

Other payables	1,830	2,004
Accrued liabilities:		
Capital expenditures	28,604	51,983
Other	78,442	69,974
Deferred premium liability	14,353	24,548
Fair value of derivative instruments	7,377	—
Other current liabilities	16,977	14,813
Total current liabilities	150,520	167,506
Long term debt, net of premium, discount and debt issuance costs	1,708,500	1,705,927
Asset retirement obligations	27,792	25,907
Fair value of derivative instruments	4,885	—
Other liabilities	52,032	58,133
Total liabilities	1,943,729	1,957,473
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 June 30, 2016 and December 31, 2015 of 4.875% Convertible Perpetual Preferred Stock, Series A; 3,527,830 shares issued and outstanding as of June 30, 2016 and December 31, 2015 of 6.500% Convertible Perpetual Preferred Stock, Series B)	53	53
Common stock ($0.01 par value, 150,000,000 shares authorized; 65,452,662 shares issued and outstanding as of June 30, 2016 and 61,928,089 shares issued and outstanding as of December 31, 2015)	658	619
Additional paid-in capital	1,089,068	1,079,513
Accumulated deficit	(1,792,971)	(1,536,354)
Total stockholders' deficit	(703,192)	(456,169)
Total liabilities and stockholders' deficit	$ 1,240,537	$ 1,501,304

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

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Sanchez Energy Corporation

Condensed Consolidated Statements of Operations (Unaudited)

(in thousands, except per share amounts)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
REVENUES:				
Oil sales	$ 65,786	$ 99,498	$ 108,468	$ 175,022
Natural gas liquid sales	21,979	17,694	37,024	31,547
Natural gas sales	23,203	23,936	45,292	45,152
Total revenues	110,968	141,128	190,784	251,721
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	44,919	35,658	89,612	69,821
Production and ad valorem taxes	6,188	8,303	10,131	16,973
Depreciation, depletion, amortization and accretion	43,342	104,717	90,308	207,374
Impairment of oil and natural gas properties	87,380	468,922	109,464	910,372
General and administrative (inclusive of stock-based compensation expense of $9,877 and $7,875, respectively, for the three months ended June 30, 2016 and 2015, and $13,222 and $15,568, respectively, for the six months ended June 30, 2016 and 2015)	23,983	21,962	43,463	43,439
Total operating costs and expenses	205,812	639,562	342,978	1,247,979
Operating loss	(94,844)	(498,434)	(152,194)	(996,258)
Other income (expense):				
Interest income and other expense	369	773	281	(1,051)
Interest expense	(31,822)	(31,500)	(63,428)	(63,058)
Earnings from equity investments	2,179	—	2,691	—
Net gains (losses) on commodity derivatives	(58,750)	(33,749)	(35,993)	7,554
Total other expense	(88,024)	(64,476)	(96,449)	(56,555)
Loss before income taxes	(182,868)	(562,910)	(248,643)	(1,052,813)
Income tax expense	—	—	—	7,442
Net loss	(182,868)	(562,910)	(248,643)	(1,060,255)
Less:				
Preferred stock dividends	(3,987)	(3,991)	(7,974)	(7,982)
Net income allocable to participating securities	—	—	—	—
Net loss attributable to common stockholders	$ (186,855)	$ (566,901)	$ (256,617)	$ (1,068,237)
Net loss per common share - basic and diluted	$ (3.20)	$ (9.91)	$ (4.38)	$ (18.74)

Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted	58,413	57,184	58,575	56,996

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

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Sanchez Energy Corporation

Condensed Consolidated Statement of Stockholders' Equity for the Six Months Ended June 30, 2016 (Unaudited)

(in thousands)

	Series A Preferred Stock		Series B Preferred Stock		Common Stock		Additional Paid-in	Accumulated	Total Stockholders'
	Shares	Amount	Shares	Amount	Shares	Amount	Capital	Deficit	Deficit
BALANCE, December 31, 2015	1,839	$ 18	3,528	$ 35	61,928	$ 619	$ 1,079,513	$ (1,536,354)	$ (456,169)
Preferred stock dividends	—	—	—	—	—	—	—	(7,974)	(7,974)
Restricted stock awards, net of forfeitures	—	—	—	—	3,889	39	(39)	—	—
Stock-based compensation	—	—	—	—	—	—	9,594	—	9,594
Net loss	—	—	—	—	—	—	—	(248,643)	(248,643)
BALANCE, June 30, 2016	1,839	$ 18	3,528	$ 35	65,817	$ 658	$ 1,089,068	$ (1,792,971)	$ (703,192)

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

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Sanchez Energy Corporation

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Six Months Ended June 30, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (248,643)	$ (1,060,255)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	90,308	207,374
Impairment of oil and natural gas properties	109,464	910,372
Stock-based compensation expense	13,222	15,568
Net losses (gains) on commodity derivative contracts	35,993	(7,554)
Net cash settlement received on commodity derivative contracts	85,120	56,104
Losses incurred on premiums for derivative contracts	12,207	121
Gain on investment in SPP	—	(31)
Amortization of deferred gain on Western Catarina Midstream Divestiture	(7,406)	—
Amortization of debt issuance costs	3,890	3,563
Accretion of debt discount, net	316	386
Deferred taxes	—	7,442
Loss on inventory market adjustment	479	—
Distributions from equity investments	101	—
Earnings from equity investments	(2,691)	—
Changes in operating assets and liabilities:		
Accounts receivable	(7,967)	34,425
Other current assets	(915)	10,228
Accounts payable	(1,247)	(28,487)
Accounts receivable - related entities	491	(3,505)
Other payables	(174)	3,406
Accrued liabilities	4,481	4,225
Other current liabilities	(159)	(5,166)
Other liabilities	—	1,188
Net cash provided by operating activities	86,870	149,404
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments for oil and natural gas properties	(172,843)	(422,841)
Payments for other property and equipment	(878)	(2,187)
Proceeds from sale of oil and natural gas properties	—	81,734
Acquisition of oil and natural gas properties	—	342

Payments for investments	(18,053)	—
Net cash used in investing activities	(191,774)	(342,952)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Financing costs	(1,758)	(400)
Preferred dividends paid	(3,987)	(7,982)
Net cash used in financing activities	(5,745)	(8,382)
Decrease in cash and cash equivalents	(110,649)	(201,930)
Cash and cash equivalents, beginning of period	435,048	473,714
Cash and cash equivalents, end of period	$ 324,399	$ 271,784
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in asset retirement obligations	$ 885	$ 1,939
Change in accrued capital expenditures	(23,379)	(77,327)
SUPPLEMENTAL DISCLOSURE:		
Cash paid for taxes	715	—
Cash paid for interest	$ 59,221	$ 62,587

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

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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), a Delaware corporation formed in August 2011, is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the horizontal development of significant resource potential from 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.

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, 2015 from the audited financial statements filed in its Annual Report on Form 10-K for the fiscal year ended December 31, 2015 (the "2015 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 2015 Annual Report, which contains a summary of the Company's significant accounting policies and other disclosures. In the opinion of management, these financial statements include the adjustments and accruals, all of which are of a normal recurring nature, which are necessary for a fair presentation of the results for the interim periods. These interim results are not necessarily indicative of results to be expected for the entire year.

As of June 30, 2016, 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 the 2015 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 March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-09 "Improvements to Employee Share-Based Payment Accounting," effective for annual and interim periods for public companies beginning after December 15, 2016, with a cumulative-effect and prospective approach to be used for implementation. ASU 2016-09 changes several aspects of the accounting for share-based payment award transactions including accounting for income taxes, classification of excess tax benefits on the statement of cash flows, forfeitures, minimum statutory tax withholding requirements and classification of employee taxes paid on the statement of cash flows when an employer withholds shares for tax-withholding purposes. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In February 2016, the FASB issued ASU No. 2016-02 “Leases (Topic 842),” effective for annual and interim periods for public companies beginning after December 15, 2018, with a modified retrospective approach to be used for implementation. ASU 2016-02 updates the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for those leases previously classified as operating leases under the old guidance. In addition, ASU 2016-02 updates the criteria for a lessee’s classification of a finance lease. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, “Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs.” In August 2015, the FASB issued ASU 2015-15, “Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements,” which is effective upon the adoption of ASU 2015-03. 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. During the first quarter 2016, the Company adopted ASU 2015-03 retrospectively to the comparable periods in this Form 10-Q. Adoption of this guidance affected the balance sheets as of December 31, 2015 as follows (in thousands):

Decrease in Long term debt, net of premium, discount and debt issuance costs of approximately $41,039

Decrease in Debt issuance costs, net (Other Assets) of approximately $41,039

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 guidance is effective for fiscal years and interim periods beginning in 2016. During the first quarter 2016, the Company adopted ASU 2015-02 retrospectively to the comparable periods in this Form 10-Q. See further disclosure around the adoption of ASU 2015-02, and the impact on the Company’s consolidated financial statements in Note 19, “Variable Interest Entities.”

In July 2015, FASB issued ASU No. 2015-11, “Simplifying the Measurement of Inventory,” effective for annual and interim periods beginning 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 we 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 we do not expect the impact to be material.

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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 for an aggregate adjusted purchase price of $557.1 million (the “Catarina Acquisition”). The effective date of the transaction was January 1, 2014. The purchase price was funded with a portion of the proceeds from the Original 6.125% Notes (as defined below in Note 6, “Long-Term Debt”) 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 sold escalating working interests in 59 wellbores located in Gonzales County, Texas to a subsidiary of SPP for an adjusted purchase price of approximately $83.4 million (the “Palmetto Disposition”). 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. On August 4, 2015, the common units of SPP were subject to a 1-for-10 reverse split, at which time we owned 105,263 common units of SPP.

Western Catarina Midstream Divestiture

On October 14, 2015, the Company and SN Catarina, LLC ("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 date, owned certain midstream gathering and processing assets located in Dimmit County and Webb County, Texas and 105,263 common units of SPP, to SPP for an adjusted purchase price of $345.8 million in cash (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 effective October 14, 2015 (the "Gathering Agreement") for an initial term of 15 years pursuant to which production from approximately 35,000 acres that we operate 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 is required to meet a minimum quarterly volume delivery commitment of 10,200 Bbls 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 Bbl for crude oil and condensate and $0.74 per Mcf for natural gas 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 Gathering Agreement and afterwards with respect to dispositions by Catarina Midstream of its ownership interest in the gathering system. The Company recorded a deferred gain of approximately $74.1 million as a result of the Gathering Agreement being accounted for as an operating lease. This deferred gain will be amortized straight-line over the firm commitment term of five years as an offset to the transportation fees paid to Catarina Midstream under the Gathering Agreement.

Note 4. Cash and Cash Equivalents

As of June 30, 2016 and December 31, 2015, cash and cash equivalents consisted of the following (in thousands):

	June 30, 2016	December 31, 2015
Cash at banks	$ 243,368	$ 35,600
Money market funds	81,031	399,448
Total cash and cash equivalents	$ 324,399	$ 435,048

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 six month periods ended June 30, 2016, the Company recorded a full cost ceiling test impairment after income taxes of $87.4 million and $109.5 million, respectively. 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 2016. The Company recorded impairment expense of $468.9 million and $910.4 million for the three and six month periods ended June 30, 2015, respectively.

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.

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Note 6. Long Term Debt

Long-term debt on June 30, 2016, consisted of $1.15 billion face value of 6.125% senior notes (consisting of $850 million in Original 6.125% Notes (defined below) and $300 million in Additional 6.125% Notes (defined below), which were issued at a premium to face value of $2.3 million), maturing on January 15, 2023, and $600 million principal amount of 7.75% senior 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 at a discount to face value of $7.0 million), maturing on June 15, 2021. During the first quarter 2016, the Company adopted ASU 2015-03 retrospectively to the comparable periods in this Form 10-Q. Adoption of this guidance affected the balance sheets as of December 31, 2015 as follows (in thousands):

Decrease in Long term debt, net of premium, discount and debt issuance costs of approximately $41,039

Decrease in Debt issuance costs, net (Other Assets) of approximately $41,039

As of June 30, 2016, and December 31, 2015, the Company's long term debt consisted of the following:

			Amount Outstanding (in thousands) as of	
	Interest Rate	Maturity date	June 30, 2016	December 31, 2015
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			(4,482)	(4,933)
Unamortized premium on Additional 6.125% Notes			1,764	1,899
Unamortized debt issuance costs			(38,782)	(41,039)
Total long-term debt			$ 1,708,500	$ 1,705,927

The components of interest expense are (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Interest on Senior Notes	$ (29,234)	$ (29,235)	$ (58,470)	$ (58,470)
Interest expense and commitment fees on credit agreement	(455)	(359)	(752)	(640)
Amortization of debt issuance costs	(1,975)	(1,748)	(3,890)	(3,563)
Amortization of discount on Additional 7.75% Notes	(226)	(226)	(451)	(452)
Amortization of premium on Additional 6.125% Notes	68	68	135	67
Total interest expense	$ (31,822)	$ (31,500)	$ (63,428)	$ (63,058)

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 and collateral agent, and the 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, as borrower, and SEP III, SN Marquis, SN Cotulla, SN Operating, LLC, SN TMS, LLC and SN Catarina, LLC as loan parties, entered into a revolving credit facility represented by a $1.5 billion Second Amended and Restated Credit Agreement with Royal Bank of Canada, as the administrative agent and collateral agent, and the lenders party thereto (together with all subsequent amendments, the ‘‘Second Amended and Restated Credit Agreement’’). The Second Amended and Restated Credit

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Agreement provides for the issuance of letters of credit, limited in the aggregate to the lesser of $80 million and the total availability thereunder. As of June 30, 2016, there were no borrowings and no letters of credit outstanding under the Second Amended and Restated Credit Agreement, which had a borrowing base of $350 million and aggregate elected commitments of $300 million. 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. All of the $300 million aggregate elected commitment amount was available for future revolver borrowings as of June 30, 2016.

The Second Amended and Restated Credit Agreement matures on June 30, 2019. The borrowing base under the Second Amended and Restated Credit Agreement is redetermined semi-annually by the lenders based on, among other things, an evaluation of the Company's and its restricted subsidiaries' oil and natural gas reserves. Semi-annual redeterminations of the borrowing base are generally scheduled to occur 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 aggregate amount of the Company's high yield debt and second lien debt, other than high yield or second lien debt issued in exchange for or to refinance existing high yield debt, permitted second lien debt incurred to refinance or replace permitted second lien debt, and permitted second lien debt representing the payment of interest in kind, (ii) interim redetermination at the election of the Company once between each scheduled redetermination, (iii) interim redetermination at the election of a majority of the lenders once between each scheduled redetermination, and (iv) if the required lenders so direct, in connection with asset sales and swap terminations during the period since the most recent borrowing base determination with a combined borrowing base value of more than 10% of the value of the proved developed oil and gas properties included in the most recent reserve report, a reduction in an amount equal to the borrowing base value, as determined by the administrative agent in its reasonable judgment, of such assets and swaps.

The Company's 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" and 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, including the SPV, defined below, an "unrestricted subsidiary" defined below, but excluding other subsidiaries 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 1.00% to 2.00% for alternate base rate borrowings and from 2.00% to 3.00% for eurodollar borrowings and letters of credit, if any, depending on the utilization of the borrowing base. The Company is also required to pay a commitment fee of 0.50% per annum on any unused aggregate elected commitment amount.

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 investments, engage in transactions with affiliates, enter into hedge transactions, and make 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) net first lien debt (defined as the excess of first lien debt over cash) to consolidated last twelve months EBITDA of not greater than 2.00 to 1.0 as of the last day of any fiscal quarter. As of June 30, 2016, the Company was in compliance with the covenants of the Second Amended and Restated Credit Agreement.

The Second Amended and Restated Credit Amendment, among other things, also (a) permits the repurchase by the Company and its restricted subsidiaries, or by a special purpose unrestricted subsidiary of the Company (the “SPV”), of the Company’s senior unsecured notes and common and preferred equity securities, from cash in excess of lender credit exposure in an aggregate amount up to approximately $298.5 million subject to certain caps on purchases of the Company’s common and preferred equity securities and other limitations; (b) permits (i) the formation and capitalization of the SPV with up to $150 million, (ii) the SPV to purchase, hold and dispose of, including by way of distribution to its immediate parent, up to $150 million of the Company’s senior unsecured notes and common and preferred equity securities, (iii) the SPV to hold cash received from its immediate parent in a deposit account maintained with a lender under the Second Amended and Restated Credit Agreement, and (iv) the SPV to distribute cash to its immediate parent; (c) requires (i) the Company to cause the SPV to distribute all cash held by it or in its name as of the close of business on December 31, 2016 to its immediate parent, (ii) the equity interests in the SPV to be pledged in favor of the secured parties and (iii) the Company to maintain all deposits, securities and commodity accounts with lenders or affiliates of lenders under the Second Amended and Restated Credit Agreement and to enter into account control agreements in favor of the administrative agent for the benefit of the secured parties in respect of each of such accounts; (d) provides that, in the event of a borrowing base deficiency, the Company shall use unrestricted cash of the Company and its subsidiaries in excess of $35 million to prepay borrowings and cash collateralize letter of credit exposure, as applicable; and (e) restricts the Company from increasing its aggregate elected commitment amount until the lenders' next regularly scheduled borrowing base redetermination, which is expected to occur in the fourth quarter 2016.

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.

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 on the notes 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 $188.8 million (after deducting the initial purchasers' discounts and offering expenses of $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 securities under the indenture. We used the net proceeds from the offering to partially fund our acquisition of contiguous acreage in McMullen County, Texas with 13 gross producing wells (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 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 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,

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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 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 $850 million in aggregate principal amount senior unsecured 6.125% notes due 2023 (the “Original 6.125% Notes”). Interest on the notes is payable on each July 15 and January 15. The Company received net proceeds from this offering of approximately $829 million, after deducting initial purchasers’ discounts and estimated offering expenses, which the Company used to repay all of the $100 million in borrowings outstanding under its 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 estimated 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 used 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 the Company’s future subordinated indebtedness. The 6.125% Notes are effectively junior in right of payment to all of the Company’s existing and future secured debt (including under the 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.

The Company has the option to redeem all or a portion of the 6.125% Notes, at any time on or after July 15, 2018 at the applicable redemption prices specified in the indenture plus accrued and unpaid interest. The Company may also redeem the 6.125% Notes, in whole or in part, at a redemption price equal to 100% of their principal amount plus a make whole premium, together with accrued and unpaid interest and additional interest, if any, to the redemption date, at any time prior to July 15, 2018. In addition, the Company may redeem up to 35% of the 6.125% Notes prior to July 15, 2017 under certain circumstances with an amount not greater than the net cash proceeds of one or more equity offerings at the redemption price specified in the indenture. The Company may also be required to repurchase the 6.125% Notes upon a change of control or if we sell certain Company assets.

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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.

Pursuant to tripartite agreements by and among the Company, U.S. Bank National Association (“U.S. Bank”) and Delaware Trust Company (“Delaware Trust”), effective May 20, 2016, U.S. Bank resigned as the Trustee, Notes Custodian, Registar and Paying Agent (“Trustee”) under the indentures of the Senior Notes and Delaware Trust was appointed as successor Trustee. No other changes to the indentures for the 6.125% Notes or the 7.75% Notes were made at the time of the change in Trustee.

Note 7. Derivative Instruments

To reduce the impact of fluctuations in oil and natural gas prices on the Company’s business and results of operations, and to protect the economics of property acquisitions at the time of execution, 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 modify the future prices to be realized. The derivative contracts may include fixed-for-floating price swaps (whereby, on the settlement date, the Company will receive or pay an amount based on the difference between a pre-determined fixed price and a variable market price for a notional quantity of production), put options (whereby the Company pays a cash premium in order to establish a fixed floor price for a notional quantity of production and, on the settlement date, receives the excess, if any, of the fixed price floor over a variable market price), and costless collars (whereby, on the settlement date, the Company receives the excess, if any, of a variable market price over a fixed floor price up to a fixed ceiling price for a notional quantity of production). In addition, the Company periodically enters into call swaptions as a way to achieve greater downside price protection than offered under prevailing fixed-for-floating price swaps by agreeing to expand the notional quantity hedged under a fixed-for-floating price swap at the counterparty’s election on a designated date.

These hedging activities, which are governed by the terms of our Second Amended and Restated Credit Agreement, are intended to support oil and natural gas prices at targeted levels and manage exposure to oil and natural gas price fluctuations. It is our policy to enter into derivative contracts only with counterparties that are creditworthy and competitive market makers. All of our derivatives with lenders, or affiliates of lenders, in our Second Amended and Restated Credit Agreement are collateralized by the assets securing our Second Amended and Restated Credit Agreement and, therefore, do not currently require the posting of cash collateral. Our existing derivatives with non-lender counterparties, as designated under the Second Amended and Restated Credit Agreement, are unsecured and do not require the posting of cash collateral. It is never the Company’s intention to enter into derivative contracts for speculative trading purposes.

All of our derivatives are accounted for as mark-to-market activities. Under ASC Topic 815, “Derivatives and Hedging,” these 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 nets derivative assets and liabilities by commodity for counterparties where a legal right to such offset exists. Changes in the derivatives’ fair values are recognized in current earnings since the Company has elected not to designate its current derivative contracts as cash flow hedges for accounting purposes.

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The following table presents derivative positions for the periods indicated as of June 30, 2016:

	July 1 - December 31, 2016	2017	2018	2019
Oil positions:				
Fixed-for-floating price swaps (NYMEX WTI):				
Hedged volume (Bbls)	1,288,000	1,460,000	-	-
Average price ($/Bbl)	$ 70.11	$ 52.13	$ -	$ -
Call swaptions (NYMEX WTI):				
Option volume (Bbls) (1)	-	365,000	-	-
Average price ($/Bbl)	$ -	$ 50.00	$ -	$ -
Put options (NYMEX WTI):				
Hedged volume (Bbls)	2,024,000	-	-	-
Average price ($/Bbl)	$ 60.00	$ -	$ -	$ -
Collars (NYMEX WTI):				
Hedged volume (Bbls)	-	730,000	-	-
Average long put price ($/Bbl)	$ -	$ 45.00	$ -	$ -
Average short call price ($/Bbl)	$ -	$ 62.00	$ -	$ -
Natural gas positions:				
Fixed-for-floating price swaps (NYMEX Henry Hub):				
Hedged volume (MMBtu)	17,175,000	27,945,000	14,600,000	7,300,000
Average price ($/MMBtu)	$ 3.15	$ 3.00	$ 3.01	$ 3.02
Call swaptions (NYMEX Henry Hub):				
Option volume (MMBtu) (1)	-	-	3,650,000	-
Average price ($/MMBtu)	$ -	$ -	$ 3.00	$ -

(1) Represent options which settle into fixed-for-floating price swaps for the respective commodity at the counterparty's election on a designated date in the preceding year.

The following table sets forth a reconciliation of the changes in fair value of the Company’s commodity derivatives for the six months ended June 30, 2016, and the year ended December 31, 2015 (in thousands):

		Year Ended

	Six Months Ended June 30, 2016	December 31, 2015
Beginning fair value of commodity derivatives	$ 178,283	$ 123,316
Net losses on crude oil derivatives	(36,370)	170,592
Net losses on natural gas derivatives	(11,830)	26,843
Net settlements on derivative contracts:		
Crude oil	(79,849)	(123,946)
Natural gas	(20,236)	(18,522)
Net premiums on derivative contracts:		
Crude oil	12,207	-
Ending fair value of commodity derivatives	$ 42,205	$ 178,283

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Balance Sheet Presentation

The Company nets derivative assets and liabilities by commodity for counterparties where legal right to such offset exists. Therefore, the Company's derivatives are presented on a net basis as "Fair value of derivative instruments" on the condensed consolidated balance sheets. The following information summarizes the gross fair values of derivative instruments, presenting the impact of offsetting the derivative assets and liabilities on the Company's condensed consolidated balance sheets (in thousands):

	June 30, 2016		
	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	$ 56,380	$ (2,114)	$ 54,266
Long-term asset	2,879	(2,678)	201
Total asset	$ 59,259	$ (4,792)	$ 54,467
Offsetting Derivative Liabilities:			
Current liability	$ (9,491)	$ 2,114	$ (7,377)
Long-term liability	(7,563)	2,678	(4,885)
Total liability	$ (17,054)	$ 4,792	$ (12,262)

	December 31, 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	$ 172,518	$ (24)	$ 172,494
Long-term asset	5,821	(32)	5,789
Total asset	$ 178,339	$ (56)	$ 178,283
Offsetting Derivative Liabilities:			
Current liability	$ (24)	$ 24	$ —
Long-term liability	(32)	32	—
Total liability	$ (56)	$ 56	$ —

Note 8. Investments

On October 2, 2015, the Company, through SN Midstream, LLC, a wholly-owned subsidiary of the Company (“SN Midstream”), entered into joint venture agreements with an affiliate of Targa to, among other things, construct a new cryogenic natural gas processing plant (the “Processing Plant”) and 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 Processing Plant joint venture agreement, SN Midstream committed to invest approximately $80 million and received a 50% ownership interest in the joint venture owning the Processing Plant. Construction is expected to be completed in 2017. In connection with the gathering pipelines joint venture agreement, SN Midstream committed to invest approximately $35 million and received a 50% ownership interest in the joint venture, Carnero Gathering, LLC (“Carnero Gathering”), owning the gathering pipelines that will connect the Company's existing Catarina gathering system to the Processing Plant. Construction on the gathering pipelines is scheduled to be completed in two phases, with both phases expected to be completed in 2016. The first phase, which connected the Catarina gathering system to the SOII Facility (defined below), was completed in February 2016. The second phase will connect the new gathering system to the Processing Plant, and is expected to be completed later this year. As of June 30, 2016, the Company had invested $26.0 million in Carnero Gathering joint venture and approximately $29.5 million in the Processing Plant joint venture. The Company is accounting for these activities as equity method investments as Targa is the operator of the joint ventures and has the most influence with respect to the normal day-to-day construction and operating decisions. We have included these equity method investment balances in the “Other Assets - Investments” long-term asset line on the balance sheet. The Company recorded earnings of approximately $1.8 million and $2.3 million from equity investments from Carnero Gathering and recorded losses of approximately $16 thousand and $27 thousand from equity investments from the Processing Plant joint venture for the three and six months ended June 30, 2016, respectively. We have included these equity method earnings and losses in the “Earnings from equity investments” line on the statement of operations. On July 5, 2016, the Company sold its interests and any remaining commitment to invest in Carnero Gathering to SPP (see further discussion in Note 20, “Subsequent Events”).

On October 2, 2015, the Company, via SN Catarina, purchased from a subsidiary of Targa a 10% undivided interest in the Silver Oak II Gas Processing Facility (the “SOII Facility”) in Bee County, Texas for a purchase price of $12.5 million. Targa owns the remaining undivided 90% interest in the SOII Facility, which is operated by Targa. Concurrently with the execution of the purchase and sale agreement for the SOII Facility, the Company entered into a firm gas processing agreement, whereby Targa began processing a firm quantity, 125,000 Mcf per day, on March 1, 2016 until the in-service date of the Processing Plant discussed above. The Company is accounting for its interest in the SOII Facility as an equity method investment as Targa is the operator and majority interest owner of the SOII Facility. As of June 30, 2016, the Company had invested $12.5 million in the SOII Facility. The Company recorded earnings of approximately $428 thousand from the equity interest in the SOII Facility for the three and six months ended June 30, 2016.

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. Although third-party quotes are utilized to assess the reasonableness of the prices and valuation techniques, there is not sufficient corroborating evidence to support classifying these assets and liabilities as Level 2.

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

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Fair Value on a Recurring Basis

The following tables set forth, by level within the fair value hierarchy, the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2016 and December 31, 2015 (in thousands):

	As of June 30, 2016			
	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	$ 81,031	$ —	$ —	$ 81,031
Oil derivative instruments:				
Swaps	—	26,353	—	26,353
Call swaptions	—	(3,081)	—	(3,081)
Collars	—	536	—	536
Puts	—	21,650	—	21,650
Gas derivative instruments:				
Swaps	—	(2,670)	—	(2,670)
Call swaptions	—	(583)	—	(583)
Total	$ 81,031	$ 42,205	$ —	$ 123,236

	As of December 31, 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	$ 399,448	$ —	$ —	$ 399,448
Oil derivative instruments:				
Swaps	—	72,887	—	72,887
Puts	—	76,583	—	76,583
Gas derivative instruments:				
Swaps	—	28,813	—	28,813
Total	$ 399,448	$ 178,283	$ —	$ 577,731

Financial Instruments: The Level 1 instruments presented in the tables above consist of money market funds and time deposits included in cash and cash equivalents on the Company's condensed consolidated balance sheets at June 30, 2016 and December 31, 2015. The Company's money market funds and time deposits represent cash equivalents backed by the assets of high-quality banks and financial institutions. The Company identified the money market funds and time deposits as Level 1 instruments due to the fact that these instruments have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Company's derivative instruments, which consist of swaps, puts, swaptions and collars, are classified as Level 2 as of June 30, 2016 and December 31, 2015 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. Swaps and collars generally have no unobservable inputs and they are classified as Level 2. Puts and swaption deriviates have inputs which are observable, either directly or indirectly, using market data. As of June 30, 2016, the Company believes that substantially all of the inputs required to calculate the fair value of puts and swaptions 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. As of December 31, 2015, the Company believes that substantially all of the inputs required to calculate the fair value of swaps and puts 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

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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 June 30, 2016 or December 31, 2015.

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. In addition, on November 20, 2015, a holder of our Series B Preferred Stock exercised its right to convert 4,500 shares our Series B Preferred Stock, at the prescribed initial conversion rate of 2.337 shares of common stock per share of Series B Preferred Stock, in exchange for 10,517 shares of our common stock. 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 are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 7.75% Notes was $502.5 million as of June 30, 2016 and was calculated using quoted market prices based on trades of such debt as of that date. The registered 6.125% Notes are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 6.125% Notes was $885.5 million as of June 30, 2016 and was calculated using quoted market prices based on trades of such debt as of that date.

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.

Revisions in estimated liabilities during the period relate primarily to changes in estimates of asset retirement costs. Revisions in estimated liabilities can also include, but are not limited to, revisions of estimated inflation rates,

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changes in property lives, and the expected timing of settlement. The changes in the asset retirement obligation for the six months ended June 30, 2016 and the year ended December 31, 2015 were as follows (in thousands):

	Six Months Ended June 30, 2016	Year Ended December 31, 2015
Abandonment liability, beginning of period	$ 25,907	$ 25,694
Liabilities incurred during period	798	6,021
Acquisitions	219	—
Divestitures	(131)	(379)
Revisions	—	(7,623)
Accretion expense	999	2,194
Abandonment liability, end of period	$ 27,792	$ 25,907

Note 11. Related Party Transactions

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 the Company 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 benefits of SOG employees and are allocated to the Company based on a fixed percentage that is reviewed quarterly and adjusted, if needed, based on a detailed analysis of actual time spent by the professional staff on Company projects and activities. General and administrative expenses such as office rent, utilities, supplies and other overhead costs, are allocated on the same percentages as the SOG employee salaries. Expenses allocated to the Company for general and administrative expenses for the three and six months ended June 30, 2016 and 2015, are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Administrative fees	$ 7,916	$ 6,602	$ 20,000	$ 12,854
Third-party expenses	573	1,250	3,657	2,016
Total included in general and administrative expenses	$ 8,489	$ 7,852	$ 23,657	$ 14,870

As of June 30, 2016 and December 31, 2015, the Company had a net receivable from SOG and other members of the Sanchez Group of $3.2 million and $3.7 million, respectively, which are reflected as “Accounts receivable—related entities” in the condensed consolidated balance sheets. The net receivable as of June 30, 2016 and December 31, 2015 consists primarily of advances paid related to leasehold and other costs paid to SOG.

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As of June 30, 2016 and December 31, 2015, the Company had a net payable to SPP of approximately $10.0 million and $4.4 million, respectively, that consists primarily of the accrual for fees associated with the Gathering Agreement (see Note 3, “Acquisitions and Divestitures” for further discussion), which is reflected in the “Other Accrued liabilities” account on the consolidated balance sheets.

Palmetto Disposition

On March 31, 2015, we completed the Palmetto Disposition discussed above to a subsidiary of SPP, which is a related party (see Note 3, “Acquisitions and Divestitures”). The second phase of the escalating working interests on the sold Palmetto wells was effective on January 1, 2016.

Western Catarina Midstream Divestiture

On October 14, 2015, we completed the Western Catarina Midstream Divestiture discussed above to SPP, which is a related party (see Note 3, “Acquisitions and Divestitures”).

Carnero Gathering Sale

On July 5, 2016, the Company sold its interests and any remaining commitment to invest in Carnero Gathering to SPP (see further discussion in Note 20, “Subsequent Events”).

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 plus an initial 3 gross (1.5 net) well drilling carry (the ‘‘Initial Well Carry’’). 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. Patricio Sanchez and Ana Lee Sanchez Jacobs, each an immediate family member of our President, Chief Executive Officer and the Executive Chairman of the Company’s Board of Directors (the “Board”), collectively with Messrs. Sanchez, Jr., Sanchez, III and Eduardo Sanchez, either directly or indirectly, own a majority of the equity interests of Sanchez Resources. Sanchez Resources is managed by our President, Eduardo Sanchez. In addition, Ms. Hink and Mr. Heinson own 15 and 65 units of phantom equity in Sanchez Resources, respectively

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 Transaction consisted of approximately $70 million in cash and the issuance of 342,760 shares of common stock 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.

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Note 12. Accrued Liabilities

The following information summarizes accrued liabilities as of June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Capital expenditures	$ 28,604	$ 51,983
Other:		
General and administrative costs	4,303	5,214
Production taxes	3,012	2,532
Ad valorem taxes	3,463	886
Lease operating expenses	29,411	27,077
Interest payable	34,266	34,265
Preferred dividends payable	3,987	—
Total accrued liabilities	$ 107,046	$ 121,957

Note 13. Stockholders' Equity

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

On June 12, 2014, the Company completed a public offering of 5,000,000 shares of common stock, at an issue price of $35.25 per share. The Company received net proceeds from this offering of $167.5 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. As of June 30, 2016, 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 June 30, 2016, all dividends accumulated through that date had been paid. The dividends accrued for the period from April 1 to June 30, 2016, were declared by the Board and paid with the Company’s common stock on July 1, 2016.

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.

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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. As of June 30, 2016, based on the initial conversion price, approximately 8,244,539 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 June 30, 2016, all dividends accumulated through that date had been paid. The dividends accrued for the period from April 1 to June 30, 2016, were declared by the Board and paid with the Company's common stock on July 1, 2016.

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 the Series B Preferred Stock pursuant to which such holders agreed to exchange an aggregate of (i) 947,490 shares of the Series A Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 2,425,574 shares of the Company’s common stock, and (ii) 756,850 shares of the Series B Preferred Stock (and waive their rights to any accrued and unpaid dividends thereon) for 2,021,066 shares of the Company’s 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 the Series B Preferred Stock pursuant to which such holders agreed to exchange an aggregate of (i) 166,025 shares of the 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 the Company’s common stock.

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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 the 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 shares of common stock 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 (i.e., as an increase in accumulated deficit) to arrive at net loss attributable to common stockholders in our condensed consolidated financial statements.

Preferred Stock Conversion—On November 20, 2015, a holder of our Series B Convertible Perpetual Preferred Stock exercised its right to convert 4,500 shares our Series B Convertible Perpetual Preferred Stock, at the prescribed initial conversion rate of 2.337 shares of common stock per share of Series B Convertible Perpetual Preferred Stock, in exchange for 10,517 shares of our common stock.

NOL Rights Plan—On July 28, 2015, the Company entered into a net operating loss carryforwards ("NOLs") 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.

Earnings (Loss) Per Share—The following table shows the computation of basic and diluted net loss per share for the three and six months ended June 30, 2016 and 2015 (in thousands, except per share amounts):

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Net loss	$ (182,868)	$ (562,910)	$ (248,643)	$ (1,060,255)
Less:				
Preferred stock dividends	(3,987)	(3,991)	(7,974)	(7,982)
Net loss allocable to participating securities(1)(2)	—	—	—	—
Net loss attributable to common stockholders	$ (186,855)	$ (566,901)	$ (256,617)	$ (1,068,237)
Weighted average number of unrestricted outstanding common shares used to calculate basic net loss per share	58,413	57,184	58,575	56,996
Dilutive shares(3)(4)	—	—	—	—
Denominator for diluted loss per common share	58,413	57,184	58,575	56,996
Net loss per common share - basic and diluted	$ (3.20)	$ (9.91)	$ (4.38)	$ (18.74)

(1) The Company's restricted shares of common stock are participating securities.

(2) For the three and six months ended June 30, 2016 and 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.

(3) The three and six months ended June 30, 2016 excludes 1,789,179 and 1,423,862 shares, respectively, of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed

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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 and six months ended June 30, 2015 excludes 981,738 and 2,291,790 shares, respectively, 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.

Note 14. Stock Based Compensation

At the Annual Meeting of Stockholders of the Company held on May 24, 2016 ("2016 Annual Meeting"), the Company's stockholders approved the Sanchez Energy Corporation Third Amended and Restated 2011 Long Term Incentive Plan (the "LTIP").

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 stock options, stock appreciation rights, restricted shares, phantom stock, other stock-based awards or stock awards, or any combination thereof. The maximum shares of common stock that may be delivered with respect to awards under the LTIP shall be (i) 17,239,790 shares plus (ii) upon the issuance of additional shares of common stock from time to time after April 1, 2016, an automatic increase equal to the lesser of (A) 15% of such issuance of additional shares of common stock and (B) such lesser number of shares of common stock as determined by the Board or Compensation Committee; provided, however, shares withheld to satisfy tax withholding obligations are not considered to be delivered under the LTIP. If any award is forfeited, cancelled, exercised, paid, or otherwise terminates or expires without the actual delivery of shares of common stock pursuant to such award (the grant of restricted stock is not a delivery of shares of common stock for this purpose), the shares of common stock subject to such award shall again be available for awards under the LTIP. There shall not be any limitation on the number of awards that may be paid in cash. Any shares delivered pursuant to an award shall consist, in whole or in part, of shares of common stock newly issued by the Company, shares of common stock acquired in the open market, from any affiliate of the Company, or any combination of the foregoing, as determined by the Board or Compensation Committee in its discretion.

The LTIP is administered by 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 stockholder approval as may be required by the exchange upon which the shares of common stock 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.

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During the three and six months ended June 30, 2016, the Company issued approximately 0.1 million shares of restricted common stock pursuant to the LTIP to directors of the Company.

During the three and six months ended June 30, 2016, the Company issued approximately 1.0 million and 4.1 million, respectively, shares 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. The majority of these shares of restricted common stock vest in equal annual amounts over a three-year period.

In February 2016 and April 2016, the Compensation Committee approved several new forms of agreement for use in equity awards pursuant to the LTIP. The new forms of agreements consist of a two new forms of restricted stock award agreements, one of which provides for vesting in equal annual increments over a three year period from the Grant Date (the "Grant Date") and the other of which provides for cliff vesting five years after the Grant Date or earlier if the common stock closing price equals or exceeds certain benchmarks as set forth in the form of agreement (the "Performance Accelerated Restricted Stock" or "PARS"), and two new forms of phantom stock agreements payable only in cash, one of which provides for vesting in equal annual increments over a three year period from the Grant Date (the "Phantom Stock") and the other of which provides for cliff vesting five years after the Grant Date or earlier if the Company's common stock closing price equals or exceeds certain benchmarks as set forth in the form of agreement (the "Performance Accelerated Phantom Stock" or "PAPS").

In February and April 2016, the PARS, PAPS and Phantom Stock awards granted to certain 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 718, "Compensation – Stock Compensation." In accordance with the guidance, the inclusion of market performance acceleration conditions does not change the accounting classification as compared to the restricted stock without market performance acceleration conditions, as both are still classified as equity within the Company's balance sheet. The Phantom Stock awards are required to be settled in cash by the Company and, per the guidance, should be classified as a liability. Compensation expense for the unvested awards is revalued at each period end and is amortized over the vesting period of the stock-based award.

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 June 30,	Six Months Ended June 30,

	2016	2015	2016	2015
Restricted stock awards, directors	$ 229	$ 286	$ 451	$ 568
Restricted stock awards, non-employees	9,648	7,589	12,771	15,001
Total stock-based compensation expense	$ 9,877	$ 7,875	$ 13,222	$ 15,569

Based on the $7.06 per share closing price of the Company's common stock on June 30, 2016, there was approximately $30.6 million of unrecognized compensation cost related to the non vested restricted shares outstanding. The cost is expected to be recognized over an average period of approximately 2.2 years.

Based on the $7.06 per share closing price of the Company's common stock on June 30, 2016, there was approximately $28.5 million of unrecognized compensation cost related to the non vested PARS, PAPS, and Phantom Stock award shares outstanding. The cost is expected to be recognized over an average period of approximately 2.63 years.

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A summary of the status of the non-vested shares for the three and six months ended June 30, 2016 and 2015 is presented below (in thousands):

	Six Months Ended June 30,	
	2016	2015
Non-vested common stock, beginning of period	4,426	2,718
Granted	4,262	3,192
Vested	(1,430)	(1,458)
Forfeited	(373)	(92)
Non-vested common stock, end of period	6,885	4,360

As of June 30, 2016, approximately 6.8 million shares remain available for future issuance to participants under the LTIP.

Note 15. Income Taxes

The Company's effective tax rate for the six months ended June 30, 2016 and 2015 was 0% and (0.7)%, 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 six months ended June 30, 2016 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 (0.7)% for the six months ended June 30, 2015 is primarily related to related to the valuation allowance on deferred tax assets.

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 to reduce the net deferred tax asset to $0 at June 30,

2016. The Company will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

At June 30, 2016, the Company had no material uncertain tax positions.

Note 16. Commitments and Contingencies

Litigation

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' 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

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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. The Consolidated Derivative Actions are currently in the early stages of discovery. A mediation in connection with the matter was held on July 7, 2016. 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. 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.

Catarina Drilling Obligation

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.

Lease Payment Obligations

As of June 30, 2016, the Company had $241.5 million in lease payment obligations that satisfy operating lease criteria. These obligations include: (i) $179.8 million in payments due with respect to firm commitment of oil and natural gas volumes under the Gathering Agreement contract signed with SPP as part of the Western Catarina Midstream Divestiture that commenced on October 14, 2015 and continues until October 13, 2020, (ii) $48.2 million for a new corporate office lease that commenced in the fourth quarter of 2014 and has an expiration date in March 2025, (iii) $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 (iv) $6.3 million for a 10 year acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas.

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 lease agreement for the acreage in Kenedy County, Texas 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 has the right to terminate the lease obligation without penalty at any time with six months advanced written notice and payment of any accrued leasehold expenses.

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Joint Venture Agreements

As discussed in Note 8, “Investments” above, SN Midstream entered into joint venture agreements with an affiliate of Targa to construct the Processing Plant and associated high pressure gathering pipelines near the Company’s Catarina asset. In connection with the joint venture agreement for the Processing Plant, SN Midstream has committed to invest approximately $80 million and receive a 50% ownership interest in the joint venture owning the Processing Plant. Construction is expected to be completed in 2017. As of June 30, 2016, the Company had invested approximately $29.5 million and has guaranteed SN Midstream’s remaining commitment to invest approximately $50.5 million in the Processing Plant joint venture.

In connection with the Carnero Gathering joint venture agreement, SN Midstream committed to invest in Carnero Gathering and receive a 50% ownership interest owning the gathering pipelines that will connect the Company's existing Catarina gathering system to the Processing Plant. Construction on the gathering pipelines is expected to be completed in 2016. As of June 30, 2016, the Company had invested approximately $26.0 million in Carnero Gathering and had guaranteed the remaining commitment of SN Midstream to invest approximately $9.0 million, which compares to remaining capital commitments of approximately $7.4 million expected as of that date. On July 5, 2016, the Company sold its interests and any remaining commitment to invest in Carnero Gathering to SPP (see further discussion in Note 20, “Subsequent Events”).

Membership percentage interests in the Processing Plant joint venture and the gathering pipelines joint venture for the Company and Targa are calculated based on the aggregate capital contributions made by each party related to the total capital contributions made by both parties. If SN Midstream fails to make capital contributions or the Company fails to fulfill the guarantee or, in the case of the Processing Plant joint venture, the Company does not elect to contribute more than $80 million (if the cost to construct the Processing Plant exceeds $160 million) our membership interest in the joint venture may be reduced. If our membership interest falls below 20% in either joint venture, we may lose appointed board seats and voting rights.

Note 17. Subsidiary Guarantors

The Company filed registration statements on Form S-3 with the SEC, which became effective January 14, 2013, June 11, 2014 and April 25, 2016 and registered, among other securities, debt securities. The subsidiaries of the Company named therein are co-registrants with the Company, and the registration statement registered guarantees of debt securities by such subsidiaries. As of June 30, 2016, such subsidiaries are 100 percent owned by the Company and any guarantees by these subsidiaries will be full and unconditional (except for customary release provisions). In the event that more than one of these subsidiaries provide guarantees of any debt securities issued by the Company, such guarantees will constitute joint and several obligations.

The Company also filed a registration statement on Form S-4 with the SEC, which became effective on June 20, 2014, pursuant to which the Company completed an offering of the 7.75% Notes, which are guaranteed by its subsidiaries named therein. As of June 30, 2016, such guarantor subsidiaries are 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several. The Company 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 June 30, 2016, such guarantor subsidiaries are 100 percent owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several.

The rules of Regulation S-X Rule 3-10 require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. See Note 18, "Condensed Consolidating Financial Information" for further discussion regarding the condensed consolidating financial information for guarantor and non-guarantor subsidiaries.

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.

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Note 18. Condensed Consolidating Financial Information

As noted above, the rules of the SEC require that condensed consolidating financial information be provided for a subsidiary that has guaranteed the debt of a registrant issued in a public offering, where the guarantee is full, unconditional and joint and several and where the voting interest of the subsidiary is 100% owned by the registrant. The Company is, therefore, presenting condensed consolidating financial information on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis (in thousands) and should be read in conjunction with the consolidated financial statements. The financial information may not necessarily be indicative of results of operations, cash flows, or financial position had such guarantor subsidiaries operated as independent entities.

Investments in subsidiaries are accounted for by the respective parent company using the equity method for purposes of this presentation. Results of operations of subsidiaries are, therefore, reflected in the parent company's investment accounts and earnings. The principal elimination entries set forth below eliminate investments in subsidiaries and intercompany balances and transactions. Typically in a condensed consolidating financial statement, the net income and equity of the parent company equals the net income and equity of the consolidated entity.

	June 30, 2016				
Assets	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 540,032	$ 12,630	$ 209,829	$ (323,796)	$ 438,695
Total oil and natural gas properties, net	-	708,608	-	-	708,608
Investment in subsidiaries	595,149	-	-	(595,149)	-
Other assets	8,306	18,479	66,449	-	93,234
Total Assets	$ 1,143,487	$ 739,717	$ 276,278	$ (918,945)	$ 1,240,537
Liabilities and Shareholders' Equity					
Current liabilities	$ 81,261	$ 122,819	$ 270,238	$ (323,798)	$ 150,520
Long-term liabilities	1,765,417	27,792	-	-	1,793,209
Total shareholders' equity (deficit)	(703,191)	589,106	6,040	(595,147)	(703,192)
Total Liabilities and Shareholders' Equity (deficit)	$ 1,143,487	$ 739,717	$ 276,278	$ (918,945)	$ 1,240,537

	December 31, 2015				
Assets				Eliminations	Consolidated

	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries		
Total current assets	$ 671,278	$ 37,005	$ 704	$ (42,369)	$ 666,618
Total oil and natural gas properties, net	-	756,103	-	-	756,103
Investment in subsidiaries	700,053	-	-	(700,053)	-
Other assets	14,481	17,737	46,365	-	78,583
Total Assets	$ 1,385,812	$ 810,845	$ 47,069	$ (742,422)	$ 1,501,304
Liabilities and Shareholders' Equity					
Current liabilities	$ 78,840	$ 88,666	$ 42,369	$ (42,369)	$ 167,506
Long-term liabilities	1,764,060	25,907	-	-	1,789,967
Total shareholders' equity (deficit)	(457,088)	696,272	4,700	(700,053)	(456,169)
Total Liabilities and Shareholders' Equity (deficit)	$ 1,385,812	$ 810,845	$ 47,069	$ (742,422)	$ 1,501,304

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	Three Months Ended June 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 110,968	$ -	$ -	$ 110,968
Total operating costs and expenses	24,107	181,174	531	-	205,812
Other income (expense)	(90,502)	638	1,840	-	(88,024)
Income (loss) before income taxes	(114,609)	(69,568)	1,309	-	(182,868)
Income tax expense	-	-	-	-	-
Equity in income (loss) of subsidiaries	(68,259)	-	-	68,259	-
Net income (loss)	$ (182,868)	$ (69,568)	$ 1,309	$ 68,259	$ (182,868)

	Three Months Ended June 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 141,128	$ -	$ -	$ 141,128
Total operating costs and expenses	22,228	616,930	404	-	639,562
Other income (expense)	(64,476)	-	-	-	(64,476)
Income (loss) before income taxes	(86,704)	(475,802)	(404)	-	(562,910)
Income tax expense	47,717	(48,112)	395	-	-
Equity in income (loss) of subsidiaries	(476,206)	-	-	476,206	-
Net income (loss)	$ (610,627)	$ (427,690)	$ (799)	$ 476,206	$ (562,910)

	Six Months Ended June 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 190,784	$ -	$ -	$ 190,784
Total operating costs and expenses	43,791	298,177	1,010	-	342,978
Other income (expense)	(99,026)	225	2,352	-	(96,449)
Income (loss) before income taxes	(142,817)	(107,168)	1,342	-	(248,643)
Income tax expense	-	-	-	-	-
Equity in income (loss) of subsidiaries	(105,825)	-	-	105,825	-
Net income (loss)	$ (248,642)	$ (107,168)	$ 1,342	$ 105,825	$ (248,643)

	Six Months Ended June 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ -	$ 251,721	$ -	$ -	$ 251,721
Total operating costs and expenses	44,014	1,203,245	720	-	1,247,979
Other income (expense)	(56,591)	36	-	-	(56,555)
Income (loss) before income taxes	(100,605)	(951,488)	(720)	-	(1,052,813)
Income tax expense	7,442	-	-	-	7,442
Equity in income (loss) of subsidiaries	(952,208)	-	-	952,208	-
Net income (loss)	$ (1,060,255)	$ (951,488)	$ (720)	$ 952,208	$ (1,060,255)

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	Six Months Ended June 30, 2016				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ 7,778	$ 79,384	$ (292)	$ -	$ 86,870
Net cash provided by (used in) investing activities	(322,233)	(172,870)	(18,026)	321,355	(191,774)
Net cash provided by (used in) financing activities	(5,745)	93,486	227,869	(321,355)	(5,745)
Net increase (decrease) in cash and cash equivalents	(320,200)	-	209,551	-	(110,649)
Cash and cash equivalents, beginning of period	434,933	-	115	-	435,048
Cash and cash equivalents, end of period	$ 114,733	$ -	$ 209,666	$ -	$ 324,399

	Six Months Ended June 30, 2015				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (33,084)	$ 182,611	$ (123)	$ -	$ 149,404
Net cash provided by (used in) investing activities	(160,464)	(340,250)	-	157,762	(342,952)
Net cash provided by (used in) financing activities	(8,382)	157,639	123	(157,762)	(8,382)
Net increase (decrease) in cash and cash equivalents	(201,930)	-	-	-	(201,930)
Cash and cash equivalents, beginning of period	473,714	-		-	473,714

Cash and cash equivalents, end of period	$ 271,784	$ -	$ -	$ -	$ 271,784

Note 19. Variable Interest Entities

During the first quarter of 2016, the Company adopted ASU 2015-02, "Consolidation—Amendments to the Consolidation Analysis," which introduces a separate analysis for determining if limited partnerships and similar entities are variable interest entities ("VIEs") and clarifies the steps a reporting entity would have to take to determine whether the voting rights of stockholders in a corporation or similar entity are substantive.

As noted above in Note 8, "Investments," the Company, through SN Midstream, entered into joint venture agreements with an affiliate of Targa in October 2015 to, among other things, construct the Processing Plant and associated high pressure gathering pipelines near the Company's Catarina asset in South Texas. In addition, the Company, via SN Catarina, purchased from a subsidiary of Targa a 10% undivided interest in the SOII Facility. The Company determined that the Carnero Gathering and Processing Plant joint ventures and ownership in the SOII Facility are more similar to limited partnerships than corporations. Under the revised guidance of ASU 2015-02, a limited partnership or similar entity with equity at risk will not be a VIE if they are able to exercise kick-out rights over the general partner(s) or they are able to exercise substantive participating rights. We concluded that the Carnero Gathering and Processing Plant joint ventures and investment in SOII Facility are VIEs under the revised guidance because we cannot remove Targa as operator and we do not have substantive participating rights. In addition, Targa has the discretion to direct activities of the VIEs regarding the risks associated with price, operations, and capital investment which have the most significant impact on the VIEs economic performance.

The Company's investment in Carnero Gathering, the Processing Plant and the SOII Facility represent VIEs that could expose the Company to losses. The amount of losses the Company could be exposed to from the Carnero Gathering joint venture is limited to the capital investment guaranteed of approximately $35 million. The amount of losses the Company could be exposed to from the Processing Plant joint venture is limited to the capital investment guaranteed of approximately $80 million. The amount of losses the Company could be exposed to from the investment in the SOII Facility is limited to the equity in the investment at any point in time.

As of June 30, 2016, SN Midstream had invested approximately $26.0 million in Carnero Gathering and the

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Company had guaranteed the remaining commitment of SN Midstream to invest approximately $9.0 million, which compares to the remaining capital commitments of approximately $7.4 million expected as of that date. As of June 30, 2016, no debt has been incurred by Carnero Gathering. On July 5, 2016, the Company sold its interests, and any remaining commitment to invest in Carnero Gathering to SPP (see further discussion in Note 20, “Subsequent Events”). The sale of the Carnero Gathering interests subsequent to the quarter end has reduced the potential exposure to losses related to the Carnero Gathering VIE to zero as of the date of this filing.

As of June 30, 2016, the Company had invested approximately $29.5 million in the Processing Plant joint venture, and approximately $12.5 million in the SOII Facility. As of June 30, 2016, no debt has been incurred by the Processing Plant joint venture or the SOII Facility. The Company is accounting for these VIEs as equity method investments and determined that Targa is the primary beneficiary of the VIEs as Targa is the operator of both the Processing Plant joint venture and the SOII Facility and has the most influence with respect to the normal day-to-day operating decisions of these facilities. We have included these VIEs in the “Other Assets - Investments” long-term asset line on the balance sheet.

Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIEs and the Company’s maximum exposure to loss as of June 30, 2016 and December 31, 2015 (in thousands):

	June 30, 2016	December 31, 2015
Capital investments	$ 67,938	$ 49,985
Earnings in equity investments	2,691	—
Equity in equity investments	$ 70,629	$ 49,985

	June 30, 2016	December 31, 2015
Equity in equity investments	$ 70,629	$ 49,985
Guarantees of capital investments	46,450	65,526
Maximum exposure to loss	$ 117,079	$ 115,511

Note 20. Subsequent Events

On July 5, 2016, SN Midstream sold its membership interests in Carnero Gathering to SPP for an initial payment of approximately $37 million and the assumption by SPP of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million (the “Carnero Gathering Transaction”). In addition, SPP is required to pay SN Midstream a monthly earnout based on gas received at Carnero Gathering’s receipt points from SN Catarina and gas delivered and processed at the Processing Plant by other producers. The membership interests disposed of constitute 50% of the outstanding membership interests in Carnero Gathering. The remaining 50% membership interests of Carnero Gathering are owned by an affiliate of Targa.

In July 2016, the Company hedged an additional 6,190,000 MMBtu of its 2017 natural gas production, in variable quantities that range from 2,500 MMBtu per day to 27,500 MMBtu per day, at a fixed price of $3.10/MMBtu.

On July 1, 2016, dividends accrued for the period from April 1 to June 30, 2016 for the Series A Preferred Stock and Series B Preferred Stock were declared by the Board and paid with the Company’s common stock.

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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 2015 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 (together with our consolidated subsidiaries, the "Company," "we," "our," "us" or similar terms), a Delaware corporation formed in August 2011, is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the onshore U.S. Gulf Coast, with a current focus on the horizontal development of significant resource potential from the Eagle Ford Shale in South Texas and the 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 in what we believe to be the core of the TMS.

We plan to invest approximately 100% of our 2016 drilling and completion capital budget in the Eagle Ford Shale. 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.

Listed below is a table of our significant transactions since January 1, 2013:

Transaction	Transaction Date	Transaction Effective Date	Core Area	Net Acreage Acquired	Net Acreage Remaining at 6/30/16	Purchase / Disposition Price (millions)
Western Catarina Midstream	10/14/2015	10/14/2015	Catarina, Eagle Ford	N/A	N/A	$ 346

Divestiture						
Palmetto Disposition	3/31/2015	1/1/2015	Palmetto, Eagle Ford	N/A	N/A	$ 83
Catarina Acquisition	6/30/2014	1/1/2014	Catarina, Eagle Ford	106,100	106,100	$ 557
Wycross Acquisition	10/4/2013	7/1/2013	Wycross, Eagle Ford	3,600	3,400	$ 230
TMS Transaction	8/16/2013	8/16/2013	TMS	69,000	60,500	$ 78
Five Mile Creek Acquisition	7/1/2013	7/1/2013	Marquis, Eagle Ford	10,300	4,900	$ 29
Cotulla Acquisition	5/31/2013	3/1/2013	Cotulla, Eagle Ford	44,500	31,200	$ 281

On October 14, 2015, the Company completed the Western Catarina Midstream Divestiture (as defined above in Note 3, “Acquisitions and Divestitures” of Part 1, Item 1. Financial Statements) for an adjusted purchase price of $345.8 million in cash. In connection with the closing of the Western Catarina Midstream Divestiture, the Company entered into the Gathering Agreement on October 14, 2015 for an initial term of 15 years pursuant to which production from approximately 35,000 acres that we operate 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 is required to meet a minimum quarterly volume delivery commitment of 10,200 Bbls per day of crude oil and condensate and 142,000 Mcf per day of natural gas, subject to certain adjustments.

On March 31, 2015, we completed the Palmetto Disposition (as defined above in Note 3, “Acquisitions and Divestitures” of Part 1, Item 1. Financial Statements) 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, on January 1, 2016, the working interest of the purchaser, a wholly-owned subsidiary of SPP, automatically increased in incremental amounts and will continue to 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.

On June 30, 2014, we completed the Catarina Acquisition in the Eagle Ford Shale with an effective date of January 1, 2014. As of the acquisition date, all proved reserves in the Catarina area were covered under lease acreage that is held by production, which acreage amounted to approximately 29,000 acres. Under the lease, we have a 100% working interest and 75% net revenue interest in the lease acreage over the Eagle Ford Shale formation from the top of

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the Austin Chalk formation to the base of the Buda Lime formation. 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 drilling at least the minimum annual well requirement necessary to maintain access to such undeveloped acreage. During the first quarter of 2016, the Company satisfied its 50 well annual commitment for the annual well commitment period, which commenced on July 1, 2015 and ended on June 30, 2016. As of June 30, 2016, the Company had drilled 20 wells that were eligible to be carried over to the well commitment period which commenced on July 1, 2016 and will end on June 30, 2017.

On October 4, 2013, we completed the Wycross Acquisition (as defined above in Note 6, "Long-Term Debt" of Part 1, Item 1. Financial Statements). The properties acquired in the Wycross Acquisition are included in our Cotulla area described below.

On August 16, 2013, we completed the TMS Transaction (as defined above in Note 11, "Related Party Transactions" of Part 1, Item 1. Financial Statements). As of June 30, 2016, the AMI held rights to approximately 135,000 (92,000 net) acres, of which we owned approximately 60,500 net acres.

In July 2013, we acquired approximately 10,300 net acres in Fayette, Gonzales and Lavaca Counties, Texas (the "Five Mile Creek Acquisition"). The properties acquired in the Five Mile Creek Acquisition are included in our Marquis area.

On May 31, 2013, we completed our acquisition of 44,461 net acres in Dimmit, Frio, LaSalle and Zavala Counties, Texas (the "Cotulla Acquisition"). We combined our Cotulla assets with our previous Maverick area to form one operating area now known as our Cotulla area. As noted above, the Cotulla area also includes the properties acquired in the Wycross Acquisition.

Our updated 2016 capital budget of $250 million to $300 million, which was announced in August 2016, is allocated approximately 85% to the drilling of 71 net wells and the completing of 75 net wells, at the midpoint of capital guidance, with the remainder allocated to facilities, leasing, and seismic activities.

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 greater than 200,000 net leasehold acres with an average working interest of approximately 93%. Using approximately 40 acre well-spacing for our Cotulla and Palmetto areas, approximately 60 acre well-spacing for our Marquis area, and approximately 75 acre well-spacing for our Catarina area 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 greater than 3,000 gross (3,000 net) locations for potential future drilling. Consistent with other operators in this area, we perform multi-stage hydraulic fracturing up to 30 stages on each well depending upon the length of the lateral section. In 2016, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In our Catarina area, located in Dimmit, LaSalle and Webb Counties, Texas we have a 100% working interest. We anticipate drilling, completion and facilities costs on our acreage to be approximately $3.3 million per well based on our current estimates and historical well costs. Current Estimated Ultimate Recovery (“EUR”) per well in Catarina is expected to range between 400 MBoe and 1,200 MBoe. We have identified between 1,300 and 1,650 gross and net

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locations for potential future drilling on our Catarina acreage. For the year 2016, we plan to spend $150 million to $160 million to spud 49 net wells and complete 52 net wells in our Catarina area.

In our Marquis area, located in southwest Fayette and northeast Lavaca Counties, Texas we have an approximate 100% working interest. We believe that our Marquis acreage lies in the volatile oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $4.0 million and $5.0 million per well based on our current estimates and historical well costs. Current EUR per well in Marquis is expected to range between 275 MBoe and 375 MBoe. We have identified up to approximately 300 gross and net locations based on 60 acre well-spacing for potential future drilling on our Marquis acreage. In 2016, we do not have any capital budgeted to spend on drilling and completions in our Marquis area.

In our Cotulla area, located in Dimmit, Frio, LaSalle, Zavala, and McMullen Counties, Texas we have an average working interest of approximately 92%. We believe that our Cotulla acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $3.0 million and $4.0 million per well based on our current estimates and historical well costs. Current EUR per well in Cotulla is expected to range between 300 MBoe and 400 MBoe. We have identified over 1,000 gross (1,000 net) locations based on 40 acre well-spacing for potential future drilling on our Cotulla area. In 2016, we plan to spend $60 million to $70 million to spud 21 net wells and complete 21 net wells in our Cotulla area.

In our Palmetto area, located in Gonzales County, Texas we have an average working interest for future development locations of approximately 49%. We believe that our Palmetto acreage lies in the volatile oil window where we anticipate drilling, completion and facilities costs on our acreage to be between $5.0 and $6.0 million per well based on our current estimates and historical well costs. Current EUR per well in Palmetto is expected to range between 500 MBoe and 600 MBoe. We have identified up to 317 gross (153 net) locations based on 40 acre well-spacing for potential future drilling in our Palmetto area. In 2016, we plan to spend $10 million to $20 million to spud two one well and complete two to three net wells in our Palmetto area.

Tuscaloosa Marine Shale

In August 2013, we acquired approximately 40,000 net undeveloped acres in what we believe to be the core of the TMS for cash and shares of our common stock. In connection with the TMS Transaction, 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 the working interests in the AMI owned at closing from three sellers (two third parties and one related party of the Company, SR), resulting in our owning an undivided 50% working interest across the AMI through the TMS formation. As of June 30, 2016, the AMI held rights to approximately 134,600 (92,300 net) acres, of which we owned approximately 60,500 net acres.

Well results in the TMS remain strong although development is currently challenged due to high well costs and depressed commodity prices. We believe that the TMS play has significant development potential and still has significant upside as changes in technology, commodity prices, and service prices occur. The average remaining lease term on the acreage is over 3 years, giving us ample time to allow other industry participants to further de-risk the play.

Recent Developments

During the fourth quarter of 2014, oil prices began a substantial and rapid decline, which continued throughout 2015 and the first half of 2016. In the face of an uncertain operating environment, the Company significantly reduced its capital budget and undertook other strategic measures to enhance liquidity. These strategic measures encompass, among other things, a focus on continuous improvement in our operations, organic growth underpinned by an extensive inventory of drilling opportunities that are economic at current prices, pursuit of distressed opportunities that may become available in the marketplace, and our relationship with SPP, which allows us to realize improved economics on the Company’s development projects without incurring equity dilution or additional leverage.

Our 2016 capital budget, announced in January 2016, was initially set at $200 million to $250 million which, at the time of the announcement, was expected to maintain production around 48,000 to 52,000 Boe per day.

Based on modest improvements in market conditions and our results for the first six months of 2016, which include stronger production, lower costs, and better well results than anticipated at the time we initially developed our

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plans for 2016, the Company has updated its 2016 capital budget to range between $250 million to $300 million. At our updated level of upstream capital spending, we anticipate that the Company will be able to maintain relatively flat production in 2016.

On July 5, 2016, the Carnero Gathering Transaction was completed whereby SN Midstream sold its membership interests in Carnero Gathering to SPP for an initial payment of approximately $37 million and the assumption by SPP of remaining capital commitments to Carnero Gathering, which are estimated at approximately $7.4 million. In addition, SPP is required to pay SN Midstream a monthly earnout based on gas received at Carnero Gathering's receipt points from SN Catarina and gas delivered and processed at the Processing Plant by other producers. The membership interests disposed of constitute 50% of the outstanding membership interests in Carnero Gathering. The remaining 50% membership interests of Carnero Gathering are owned by an affiliate of Targa.

Outlook

Although capital markets have shown signs of improvement recently, our operating environment continues to be influenced by commodity price volatility. As a result, we face persistent uncertainty with respect to the future of our industry, which may continue through the remainder of 2016 and later years. In this environment, the Company plans to carefully manage its capital spending and operating activities in order to preserve liquidity. The Company maintains significant operational and financial flexibility to respond to changes in market and operating conditions, and our capital budget remains at all times subject to adjustment.

We expect to use a portion of our cash on hand, internally generated cash flows from operations, and funds raised through the selective sale of certain assets, including the sale of interests in Carnero Gathering, to fund our remaining 2016 capital expenditures, and currently project no borrowings under the Second Amended and Restated Credit Agreement for purposes of our development activity at our planned level of capital spending. We will continuously evaluate our capital spending and operating activities in light of realized commodity prices and the results of our operations, and may make further adjustments to our capital spending program as warranted. In addition, we will continuously review acquisition opportunities involving third-party assets or transactions with other members of the Sanchez Group and SPP.

For the 12-month period ended June 30, 2016, the oil price (WTI Cushing) used in the SEC methodology for calculating PV 10 and Standardized Measures, and for performing impairment tests under the full cost method, which is calculated as the unweighted arithmetic average of the first of the month reported price for the 12 month historical period, was $43.12 per Bbl. The average natural gas price (Henry Hub) calculated in the same manner was $2.24 per MMBtu. At these price levels, SEC prices for oil and natural gas have decreased approximately 7% since March 31, 2016, and have decreased 19% and 18%, respectively, since December 31, 2015.

As a result of less favorable commodity prices adversely impacting our proved reserve values, and the impact of commodity price volatility on our future drilling opportunities, we recorded a full cost ceiling test impairment after income taxes of $87.4 million and $109.5 million, for the three and six months ended June 30, 2016, respectively. Based on known changes in historical first-day-of-the-month-prices and continuing weakness in commodity prices, there is a reasonable likelihood that the Company will incur additional impairments to our full cost pool in 2016 absent a material addition to proved reserves and/or a material reduction in future development costs.

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Results of Operations

Three Months Ended June 30, 2016 Compared to Three Months Ended June 30, 2015

Revenue and Production

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

	Three Months Ended June 30,		Increase (Decrease) 2016 vs 2015	
	2016	2015	$	%
Net Production:				
Oil (MBbl)	1,634	1,917	(283)	(15) %
NGLs (MBbl)	1,519	1,467	52	4 %
Natural gas (MMcf)	11,601	9,135	2,466	27 %
Total oil equivalent (MBoe)	5,087	4,907	180	4 %
Average Sales Price Excluding Derivatives(1):				
Oil ($ per Bbl)	$ 40.25	$ 51.90	$ (11.65)	(22) %
NGLs ($ per Bbl)	14.47	12.06	2.41	20 %
Natural gas ($ per Mcf)	2.00	2.62	(0.62)	(24) %
Oil equivalent ($ per Boe)	$ 21.82	$ 28.76	$ (6.94)	(24) %
Average Sales Price Including Derivatives(2):				
Oil ($ per Bbl)	$ 54.88	$ 63.75	$ (8.87)	(14) %
NGLs ($ per Bbl)	14.47	12.06	2.41	20 %
Natural gas ($ per Mcf)	2.93	3.21	(0.28)	(9) %
Oil equivalent ($ per Boe)	$ 28.64	$ 34.50	$ (5.86)	(17) %
REVENUES(1):				
Oil sales	$ 65,786	$ 99,498	$ (33,712)	(34) %
NGL sales	21,979	17,694	4,285	24 %
Natural gas sales	23,203	23,936	(733)	(3) %
Total revenues	$ 110,968	$ 141,128	$ (30,160)	(21) %

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

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

	Three Months Ended June 30, 2016	2015
Production:		
Oil - MBbl		
Catarina	963	835
Marquis	179	408
Cotulla	382	501
Palmetto	98	158
Other	12	16
Total	1,634	1,917
NGLs - MBbl		
Catarina	1,395	1,298
Marquis	40	59
Cotulla	65	75
Palmetto	19	35
Other	—	—
Total	1,519	1,467
Natural gas - MMcf		
Catarina	10,884	8,130
Marquis	166	246
Cotulla	417	544
Palmetto	132	212
Other	2	3
Total	11,601	9,135
Net production volumes:		
Total oil equivalent (Mboe)	5,087	4,907
Average daily production (Boe/d)	55,901	53,923
Average Sales Price (1):		
Oil ($ per Bbl)	$ 40.25	$ 51.90
NGLs ($ per Bbl)	$ 14.47	$ 12.06
Natural gas ($ per Mcf)	$ 2.00	$ 2.62
Oil equivalent ($ per Boe)	$ 21.82	$ 28.76
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 8.83	$ 7.27
Production and ad valorem taxes	$ 1.22	$ 1.69
General and administrative (2)	$ 2.77	$ 2.87
Depreciation, depletion, amortization and accretion	$ 8.52	$ 21.34
Impairment of oil and natural gas properties	$ 17.18	$ 95.56

(1) Excludes the impact of derivative instruments.

(2) For the three months ended June 30, 2016 and 2015, general and administrative excludes non-cash stock-based compensation expense of approximately $9.9 million ($1.94 per Boe) and $7.9 million ($1.60 per Boe), respectively.

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Net Production. Production increased from 4,907 MBoe for the three months ended June 30, 2015 to 5,087 MBoe for the three months ended June 30, 2016 due to our drilling program. The number of gross wells producing at the period end and the production for the periods were as follows:

	Three Months Ended June 30,			
	2016		2015	
	# Wells	MBoe	# Wells	MBoe
Catarina	311	4,172	238	3,487
Cotulla	153	517	103	509
Marquis	103	247	139	667
Palmetto	76	139	72	228
Other	14	12	13	16
Total	657	5,087	565	4,907

For the three months ended June 30, 2016, 32% of our production was oil, 30% was NGLs and 38% was natural gas compared to the three months ended June 30, 2015 production that was 39% oil, 30% NGLs and 31% 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 NGLs and natural gas production as compared to oil production from this area. Since the acquisition of the Catarina wells, production from Catarina has continued to increase in proportion to the total production, and as such, a higher proportion of NGLs and natural gas was produced as compared to oil.

Revenues. Oil, NGLs, and natural gas sales revenues totaled approximately $111.0 million and $141.1 million for the three months ended June 30, 2016 and 2015, respectively. Oil and Natural gas sales revenues for the three months ended June 30, 2016 decreased $33.7 million and $0.7 million, respectively, while sales revenue for NGLs for the three months ended June 30, 2016 increased $4.3 million, as compared to the three months ended June 30, 2015.

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 June 30, 2016 to the quarter ended June 30, 2015 (in thousands, except average sales price). The decrease in average realized prices from the quarter ended June 30, 2015 to the quarter ended June 30, 2016 can be attributed to both the significant decline in commodity prices and the increased percentage of NGLs and natural gas production relative to oil production that comprises our total production mix.

Q2 2016 Production Volume	Q2 2015 Production Volume	Production Volume Difference	Q2 2015 Average Sales Price	Revenue Increase/(Decrease) due to Production

Oil (MBbl)	1,634	1,917	(283)	$ 51.90	$ (14,661)
NGLs (MBbl)	1,519	1,467	52	$ 12.06	$ 621
Natural gas (MMcf)	11,601	9,135	2,466	$ 2.62	$ 6,461
Total oil equivalent (MBoe)	5,087	4,907	180	$ 28.76	$ (7,579)

	Q2 2016 Average Sales Price	Q2 2015 Average Sales Price	Average Sales Price Difference	Q2 2016 Production Volume	Revenue Increase/(Decrease) due to Price
Oil (MBbl)	$ 40.25	$ 51.90	$ (11.65)	1,634	$ (19,051)
NGLs (MBbl)	$ 14.47	$ 12.06	$ 2.41	1,519	$ 3,664
Natural gas (MMcf)	$ 2.00	$ 2.62	$ (0.62)	11,601	$ (7,194)
Total oil equivalent (MBoe)	$ 21.82	$ 28.76	$ (6.94)	5,087	$ (22,581)

Additionally, a 10% increase in our average realized sales prices, excluding the impact of derivatives, would have increased our revenues for the three months ended June 30, 2016 by approximately $11.1 million, and a 10% decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the three months ended June 30, 2016 by approximately $11.1 million.

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Operating Costs and Expenses

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

	Three Months Ended June 30,		Increase (Decrease) 2016 vs 2015	
	2016	2015	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 44,919	$ 35,658	$ 9,261	26 %
Production and ad valorem taxes	6,188	8,303	(2,115)	(25)%
Depreciation, depletion, amortization and accretion	43,342	104,717	(61,375)	(59)%
Impairment of oil and natural gas properties	87,380	468,922	(381,542)	(81)%
General and administrative (1)	23,983	21,962	2,021	9 %
Total operating costs and expenses	205,812	639,562	(433,750)	(68)%
Interest income and other expense	369	773	(404)	(52)%
Interest expense	(31,822)	(31,500)	(322)	1 %
Earnings from equity investments	2,179	—	2,179	*
Net gains on commodity derivatives	(58,750)	(33,749)	(25,001)	74 %
Income tax expense	—	—	—	

(1) Inclusive of stock-based compensation expense of $9.9 million and $7.9 million for the three months ended June 30, 2016 and 2015, respectively.

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 26% to approximately $44.9 million for the three months ended June 30, 2016 as compared to $35.7 million for the same period in 2015. The increase in oil and natural gas production expenses in the second quarter of 2016 compared to the same period of 2015 is attributable to our increased production activities and well count on our existing acreage. In addition, the increase in gathering and transportation costs paid to SPP associated with the Gathering Agreement that began in October 2015 outweighs the operating cost savings that were previously incurred by the Company through our ownership of the midstream assets. Our average production expenses increased from $7.27 per Boe during the three months ended June 30, 2015 to $8.83 per Boe for the three months ended June 30, 2016. This increase was due primarily to the costs paid to SPP associated with the Gathering Agreement. 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.

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 $6.2 million and $8.3 million for the three months ended June 30, 2016 and 2015, respectively. The decrease in production and ad valorem taxes in the second quarter of 2016 compared to the same period in 2015 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 $1.69 per Boe during the three months ended June 30, 2015 to $1.22 per Boe for the three months ended June 30, 2016. 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 for 2016. 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

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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 decreased $61.4 million from $104.7 million ($21.34 per Boe) for the three months ended June 30, 2015 to $43.3 million ($8.52 per Boe) for the three months ended June 30, 2016. The majority of the decrease in DD&A is related to the decrease in depletion rate due to full cost ceiling impairments recorded in 2015 and the decrease in the full cost pool related to the Western Catarina Midstream Divestiture in the fourth quarter of 2015. Higher production during the three months ended June 30, 2016 as compared to the same period in 2015 resulted in a $3.8 million increase in depletion expense and the decrease in the depletion rate resulted in a $65.3 million decrease in depletion expense.

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 after income taxes of $87.4 million for the three months ended June 30, 2016. The impact of less favorable commodity prices adversely affecting proved reserve values was the main contributor to the ceiling impairment recorded at June 30, 2016. 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 after income taxes of $468.9 million for the three months ended June 30, 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 2016.

If the simple average of oil, natural gas, and NGL prices as of the first day of each month for the trailing 12 month period ended June 30, 2016 had been $42.91 per Bbl of oil, $2.28 per MMBtu for natural gas, and $19.20 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 increased by approximately $16.5 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 July 2016 and the July 2016 prices were held constant for the remaining two months. The increase in the ceiling test limitation is a result of the increase in the simple average for natural gas and NGL prices as compared to the simple average prices for the trailing 12-month period ended June 30, 2016. Due to the Company’s production profile, the positive impact on natural gas and NGL revenues and production from the increase in natural gas and NGL prices outweighed the decrease in oil revenues and production from the decrease in the oil simple average price. 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 prices for oil, natural gas, and NGLs. 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 $24.0 million for the three months ended June 30, 2016 compared to $22.0 million for the same period in 2015. Excluding the stock based compensation, G&A expenses for the three months ended June 30, 2016 and 2015 were $14.1 million and $14.1 million, respectively, which is consistent period over period. Our G&A expenses, excluding stock based compensation expense, decreased from $2.87 per Boe during the three months ended June 30, 2015 to $2.77 per Boe for the three months ended June 30, 2016.

For the three months ended June 30, 2016 and 2015, we recorded non cash stock based compensation expense of approximately $9.9 million and $7.9 million, respectively. The increase in the stock-based compensation expense

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amount was caused by an increase in awards outstanding and the associated amortization expense recognized. This increase was offset by a decrease in the Company's stock price from the three months ended June 30, 2015 to the three months ended June 30, 2016. 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 June 30, 2016, interest expense totaled $31.8 million and included $2.0 million in amortization of debt issuance costs. This is compared to the three months ended June 30, 2015, for which interest expense totaled $31.5 million and included $1.7 million in amortization of debt issuance costs. The interest expense incurred during the three months ended June 30, 2016 and June 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 2015.

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 June 30, 2016, we recognized a total loss of $58.8 million on our commodity derivative contracts primarily related to mark-to-market losses on oil and natural gas derivatives of $59.3 million and $34.2 million, respectively, associated with the increase in oil and natural gas prices during the second quarter 2016. These losses were slightly offset by settlement gains on oil and natural gas derivatives of $23.9 million and $10.8 million, respectively. 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 June 30, 2015, we recognized a total loss of $33.8 million on our commodity derivative contracts primarily related to losses associated with deferred premium payment liabilities on crude oil puts entered into in April 2015 and mark-to-market losses due to oil price increases during the quarter. The total net loss also included a net gain of $28.1 million associated with the settlements of commodity derivative contracts. These gains were primarily the result of the decreases in commodity prices during the period.

Income Tax Expense. For the three months ended June 30, 2016, the Company did not record income tax expense. Due to the full cost ceiling impairment recorded and decrease in revenues during the respective quarters, the Company was in a net loss position. Our effective tax rate for the three months ended June 30, 2016 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 recorded during the period. Our effective tax rate for the three months ended June 30, 2015 was 0%. This was due to the net loss recorded for the quarter and any resulting income tax benefit being eliminated by a full valuation allowance. 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 June 30, 2015 is related to a valuation allowance recorded during the period.

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Six Months Ended June 30, 2016 Compared to Six Months Ended June 30, 2015

Revenue and Production

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

	Six Months Ended June 30,		Increase (Decrease) 2016 vs 2015	
	2016	2015	$	%
Net Production:				
Oil (MBbl)	3,274	3,701	(427)	(12)%
NGLs (MBbl)	3,208	2,588	620	24 %
Natural gas (MMcf)	22,497	16,127	6,370	39 %
Total oil equivalent (MBoe)	10,232	8,977	1,255	14 %
Average Sales Price Excluding Derivatives(1):				
Oil ($ per Bbl)	$ 33.13	$ 47.30	$ (14.17)	(30)%
NGLs ($ per Bbl)	11.54	12.19	(0.65)	(5) %
Natural gas ($ per Mcf)	2.01	2.80	(0.79)	(28)%
Oil equivalent ($ per Boe)	$ 18.65	$ 28.04	$ (9.39)	(34)%
Average Sales Price Including Derivatives(2):				
Oil ($ per Bbl)	$ 53.79	$ 60.66	$ (6.87)	(11)%
NGLs ($ per Bbl)	11.54	12.19	(0.65)	(5) %
Natural gas ($ per Mcf)	2.91	3.30	(0.39)	(12)%
Oil equivalent ($ per Boe)	$ 27.24	$ 34.45	$ (7.21)	(21)%
REVENUES(1):				
Oil sales	$ 108,468	$ 175,022	$ (66,554)	(38)%
Natural gas liquids sales	37,024	31,547	5,477	17 %
Natural gas sales	45,292	45,152	140	0 %
Total revenues	$ 190,784	$ 251,721	$ (60,937)	(24)%

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

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

	Six Months Ended June 30, 2016	2015
Production:		
Oil - MBbl		
Catarina	1,869	1,398
Marquis	397	881
Cotulla	771	998
Palmetto	211	386
Other	26	37
Total	3,274	3,701
NGLs - MBbl		
Catarina	2,941	2,209
Marquis	87	124
Cotulla	136	169
Palmetto	44	86
Other	—	—
Total	3,208	2,588
Natural gas - MMcf		
Catarina	21,037	13,980
Marquis	359	498
Cotulla	818	1,156
Palmetto	278	472
Other	5	21
Total	22,497	16,127
Net production volumes:		
Total oil equivalent (MBoe)	10,232	8,977
Average daily production (Boe/d)	56,220	45,597
Average Sales Price (1):		
Oil ($ per Bbl)	$ 33.13	$ 47.30
NGLs ($ per Bbl)	$ 11.54	$ 12.19
Natural gas ($ per Mcf)	$ 2.01	$ 2.80
Oil equivalent ($ per Boe)	$ 18.65	$ 28.04
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 8.76	$ 7.78
Production and ad valorem taxes	$ 0.99	$ 1.89
General and administrative (2)	$ 2.96	$ 3.10
Depreciation, depletion, amortization and accretion	$ 8.83	$ 23.10
Impairment of oil and natural gas properties	$ 10.70	$ 101.41

(1) Excludes the impact of derivative instruments.

(2) For the six months ended June 30, 2016 and 2015, general and administrative excludes non-cash stock-based compensation expense of approximately $13.2 million ($1.29 per Boe) and $15.6 million ($1.73 per Boe), respectively.

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Net Production. Production increased from 8,977 MBoe for the six months ended June 30, 2015 to 10,232 MBoe for the six months ended June 30, 2016 due to our drilling program. The number of gross wells producing at the period end and the production for the periods were as follows:

	Six Months Ended June 30,			
	2016		2015	
	# Wells	MBoe	# Wells	MBoe
Catarina	311	8,316	238	1,088
Cotulla	153	1,043	103	1,360
Marquis	103	545	139	5,937
Palmetto	76	301	72	551
Other	14	27	13	41
Total	657	10,232	565	8,977

For the six months ended June 30, 2016, 32% of our production was oil, 31% was NGLs and 37% was natural gas compared to the six months ended June 30, 2015 production that was 41% oil, 29% NGLs and 30% 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 NGLs and natural gas production as compared to oil production from this area. Since the acquisition of the Catarina wells, production from Catarina has continued to increase in proportion to total production, and as such, a higher proportion of NGLs and natural gas was produced as compared to oil.

Revenues. Oil, NGLs, and natural gas sales revenues totaled approximately $190.8 million and $251.7 million for the six months ended June 30, 2016 and 2015, respectively. Oil sales revenues for the six months ended June 30, 2016 decreased $66.6 million, while sales revenue for NGLs for the six months ended June 30, 2016 increased $5.4 million as compared to the six months ended June 30, 2015. Natural gas sales were consistent for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015.

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 six months ended June 30, 2016 to the six months ended June 30, 2015 (in thousands, except average sales price). The decrease in average realized prices from the six months ended June 30, 2015 to the six months ended June 30, 2016 can be attributed to both the significant decline in commodity prices and the increased percentage of NGLs and natural gas production relative to oil production that comprises our total production mix.

	YTD Q2 2016 Production	YTD Q2 2015 Production	Production Volume	YTD Q2 2015	Revenue Increase/(Decrease)

	Volume	Volume	Difference	Average Sales Price	due to Production
Oil (MBbl)	3,274	3,701	(427)	$ 47.30	$ (20,178)
NGLs (MBbl)	3,208	2,588	620	$ 12.19	$ 7,552
Natural gas (MMcf)	22,497	16,127	6,370	$ 2.80	$ 17,833
Total oil equivalent (MBoe)	10,232	8,977	1,255	$ 28.04	$ 5,207

	YTD Q2 2016 Average Sales Price	YTD Q2 2015 Average Sales Price	Average Sales Price Difference	YTD Q2 2016 Volume	Revenue Increase/(Decrease) due to Price
Oil (MBbl)	$ 33.13	$ 47.30	$ (14.17)	3,274	$ (46,376)
NGLs (MBbl)	$ 11.54	$ 12.19	$ (0.65)	3,208	$ (2,075)
Natural gas (MMcf)	$ 2.01	$ 2.80	$ (0.79)	22,497	$ (17,693)
Total oil equivalent (MBoe)	$ 18.65	$ 28.04	$ (9.39)	10,232	$ (66,144)

Additionally, a 10% increase in our average realized sales prices, excluding the impact of derivatives, would have increased our revenues for the six months ended June 30, 2016 by approximately $19.1 million, and a 10%

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decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the six months ended June 30, 2016 by approximately $19.1 million.

Operating Costs and Expenses

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

	Six Months Ended June 30,		Increase (Decrease) 2016 vs 2015	
	2016	2015	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 89,612	$ 69,821	$ 19,791	28 %
Production and ad valorem taxes	10,131	16,973	(6,842)	(40) %
Depreciation, depletion, amortization and accretion	90,308	207,374	(117,066)	(56) %
Impairment of oil and natural gas properties	109,464	910,372	(800,908)	(88) %
General and administrative (1)	43,463	43,439	24	*
Total operating costs and expenses	342,978	1,247,979	(905,001)	(73) %
Interest income and other expense	281	(1,051)	1,332	(127) %
Interest expense	(63,428)	(63,058)	(370)	1 %
Earnings from equity investments	2,691	—	2,691	*
Net gains on commodity derivatives	(35,993)	7,554	(43,547)	*
Income tax expense	—	7,442	(7,442)	*

(1) Inclusive of stock-based compensation expense of $13.2 million and $15.6 million for the six months ended June 30, 2016 and 2015, respectively.

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 28% to approximately $89.6 million for the six months ended June 30, 2016 as compared to $69.8 million for the same period in 2015. The increase in oil and natural gas production expenses in the second quarter of 2016 compared to the same period of 2015 is attributable to our increased production activities and well count on our existing acreage. In addition, the increase in gathering and transportation costs paid to SPP associated with the Gathering Agreement that began in October 2015 outweighs the operating cost savings that were previously incurred by the Company through our ownership of the midstream assets. Our average production expenses increased from $7.78 per Boe during the six months ended June 30, 2015 to $8.76 per Boe for the six months ended June 30, 2016.

This increase was due primarily to the costs paid to SPP associated with the Gathering Agreement. 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.

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 $10.1 million and $17.0 million for the six months ended June 30, 2016 and 2015, respectively. The decrease in production and ad valorem taxes in the second quarter of 2016 compared to the same period in 2015 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 $1.89 per Boe during the six months ended June 30, 2015 to $0.99 per Boe for the six months ended June 30, 2016. 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 for 2016. 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.

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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 decreased $117.1 million from $207.4 million ($23.1 per Boe) for the six months ended June 30, 2015 to $90.3 million ($8.83 per Boe) for the six months ended June 30, 2016. The majority of the decrease in DD&A is related to the decrease in depletion rate due to full cost ceiling impairments recorded in 2015 and the decrease in the full cost pool related to the Western Catarina Midstream Divestiture transaction that occurred during the fourth quarter of 2015. Higher production during the six months ended June 30, 2016 as compared to the same period in 2015 resulted in a $29.0 million increase in depletion expense and the decrease in the depletion rate resulted in a $146.0 million decrease in depletion expense.

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 after income taxes of $109.5 million for the six months ended June 30, 2016. The impact of less favorable commodity prices adversely affecting proved reserve values was the main contributor to the ceiling impairment recorded at June 30, 2016. 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 after income taxes of $910.4 million for the six months ended June 30, 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 2016.

General and Administrative Expenses. Our general and administrative ("G&A") expenses, including stock based compensation expense, totaled $43.5 million for the six months ended June 30, 2016 compared to $43.4 million for the same period in 2015. Excluding the stock based compensation, G&A expenses for the six months ended June 30, 2016 and 2015 were $30.2 million and $27.9 million, respectively. This increase was due primarily to additional costs for added personnel of SOG performing services for the Company. Our G&A expenses, excluding stock based compensation expense, decreased from $3.10 per Boe during the six months ended June 30, 2015 to $2.96 per Boe for the six months ended June 30, 2016.

For the six months ended June 30, 2016 and 2015, we recorded non cash stock based compensation expense of approximately $13.2 million and $15.6 million, respectively. The decrease in the stock-based compensation expense amount was caused by a decrease in the Company’s stock price during the second quarter 2016. 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 six months ended June 30, 2016, interest expense totaled $63.4 million and included $3.9 million in amortization of debt issuance costs. This is compared to the six months ended June 30, 2015, for which interest expense totaled $63.1 million and included $3.6 million in amortization of debt issuance costs. The interest expense incurred during the six months ended June 30, 2016 and June 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 2015.

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 six months ended June 30, 2016, we recognized a total loss of $36.0 million on our commodity derivative contracts primarily related to mark-to-market losses on oil and natural gas derivatives of $91.8 million and $32.1 million, respectively, associated with the increase in oil and natural prices during the second quarter 2016. These mark-to-market losses were offset by settlements of commodity derivative contracts of $87.9 million. 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 six months ended June 30, 2015, we recognized a total loss of $43.5 million on our commodity derivative contracts primarily related to mark-to-market losses on commodity derivatives of $73.9 million, associated with the increase in oil and natural prices during the second quarter 2015, and losses associated with deferred premium payment liabilities on crude oil puts entered into in April 2015. These mark-to-market losses were offset by settlements of commodity derivative contracts of $30.4 million. These gains were primarily the result of the decreases in commodity prices during the period.

Income Tax Expense. For the six months ended June 30, 2016, the Company did not record income tax expense. Due to the full cost ceiling impairment recorded and decrease in revenues during the respective quarters, the Company was in a net loss position. Our effective tax rate for the six months ended June 30, 2016 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 recorded during the period. For the six months ended June 30, 2015, the Company recorded income tax expense of $7.4 million. Our effective tax rate for the six months ended June 30, 2015 was (0.7)%. The primary 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 (0.7)% for the six months ended June 30, 2015 is related to a valuation allowance 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 June 30, 2016, our critical accounting policies were consistent with those discussed in our 2015 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 June 30, 2016, we had approximately $324 million in cash and cash equivalents and $300 million in borrowing capacity at the aggregate elected commitment amount under the Second Amended and Restated Credit Agreement with a syndicate of 16 participating banks, resulting in available liquidity of approximately $624 million. The borrowing base under the Second Amended and Restated Credit Agreement was set at $350 million in March 2016. Pursuant to amendments to the Second Amended and Restated Credit Agreement executed at that time, the $300 million aggregate elected commitment amount will remain fixed until the lenders' next regularly scheduled borrowing base redetermination, which is expected to occur in the fourth quarter 2016.

Based on modest improvements in market conditions and our results for the first six month of 2016, which include stronger production, lower costs, and better well results than anticipated at the time we initially developed our

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plans for 2016, the Company has updated its 2016 capital budget to range between $250 million to $300 million, which is expected to result in single digit growth in our production relative to the prior year. We expect to use a portion of our cash on hand, internally generated cash flows from operations, and funds raised through the selective sale of certain assets, including the sale of interests in Carnero Gathering, to fund our remaining 2016 capital expenditures, and currently project no borrowings under the Second Amended and Restated Credit Agreement for purposes of our development activity at our planned level of capital spending. We believe that our cash on hand and internally generated cash flows from operations will adequately meet our liquidity needs for the next twelve months.

For a description of current and previous credit agreements along with the indentures covering our Senior Notes refer to Note 6, “Long Term Debt” of Part 1, Item 1. Financial Statements.

In April 2016, the Company entered into swaps to hedge 1,000 Bbl per day of oil in 2017 at a fixed price of $50.00/Bbl and 10,000 MMBtu per day of natural gas in 2018 at a fixed price of $3.00/MMBtu. The Company’s counterparty on the swaps has the right, under certain circumstances, to increase the volumes hedged to cover an additional 1,000 Bbl per day of oil in 2017 and an additional 10,000 MMBtu per day of natural gas in 2018 at the same fixed prices. In May 2016, the Company entered into an additional swap to hedge 10,000 MMBtu per day of natural gas in 2018 at a fixed price of $3.00/MMBtu. Please refer to Note 7, “Derivative Instruments” for a description of all of the Company’s derivatives covering anticipated future production as of June 30, 2016.

Cash Flows

Our cash flows for the six months ended June 30, 2016 and 2015 (in thousands) are as follows:

	Six Months Ended June 30, 2016	2015
Cash Flow Data:		
Net cash provided by operating activities	$ 86,870	$ 149,404
Net cash used in investing activities	$ (191,774)	$ (342,952)
Net cash used in financing activities	$ (5,745)	$ (8,382)

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $86.9 million for the six months ended June 30, 2016 compared to $149.4 million for the same period in 2015. This decrease was primarily related to the unfavorable impact of changes in working capital items, including lower revenues due to the impact of lower average commodity prices between these periods. This decrease was partially offset by higher cash settlements received on commodity derivative contracts between these periods.

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

Net Cash Used in Investing Activities. Net cash flows used in investing activities totaled $191.8 million for the six months ended June 30, 2016 compared to $343.0 million for the same period in 2015. Capital expenditures for leasehold and drilling activities for the six months ended June 30, 2016 totaled $173.0 million, primarily associated with bringing online 17 gross wells. In addition, we invested $18.1 million in the joint ventures with Targa and invested $0.9 million in other property and equipment during the six months ended June 30, 2016. For the six months ended March 31, 2015, we incurred capital expenditures of $422.8 million, primarily associated with bringing online 36 gross wells. In connection with the Palmetto Disposition on March 31, 2015, we received cash consideration of approximately $81.6 million. In addition, we invested $2.2 million in other property and equipment during the six months ended June 30, 2015.

Net Cash Used in Financing Activities. Net cash flows used in financing activities totaled an outflow of $5.7 million for the six months ended June 30, 2016 compared to $8.4 million for the same period in 2015. During the six months ended June 30, 2016, we made payments of approximately $4.0 million for dividends on our Series A Preferred Stock and Series B Preferred Stock and payments of approximately $1.7 million for deferred financing costs associated with the Sixth Amendment to the Second Amended and Restated Credit Agreement. During the six months ended June 30, 2015, we made payments of $8.0 million for dividends on our Series A Convertible Perpetual Preferred Stock and Series B Convertible Perpetual Preferred Stock.

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Off Balance Sheet Arrangements

As of June 30, 2016, 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.

There have been no material changes in our contractual obligations during the three months ended June 30, 2016.

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 and divestiture 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

- Certain other items that we deem appropriate.

Less:

- Amortization of deferred gain on Western Catarina Midstream Divestiture;

- Interest income; and

- Certain other 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

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presented in accordance with U.S. GAAP. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net loss	$ (182,868)	$ (562,910)	$ (248,643)	$ (1,060,255)
Plus:				
Interest expense	31,822	31,500	63,428	63,058
Net losses (gains) on commodity derivative contracts	58,750	33,749	35,993	(7,554)
Net settlements received on commodity derivative contracts (1)	34,720	28,138	87,878	57,493
Depreciation, depletion, amortization and accretion	43,342	104,717	90,308	207,374
Impairment of oil and natural gas properties	87,380	468,923	109,464	910,372
Stock-based compensation expense	9,877	7,875	13,222	15,569
Acquisition and divestiture costs included in general and administrative	422	—	422	—
Write off of joint venture receivable, non-recurring	—	—	—	2,251
Income tax expense	—	—	—	7,442
Less:				
Amortization of deferred gain on Western Catarina Midstream Divestiture	(3,703)	—	(7,406)	—
Interest income	(158)	(91)	(484)	(184)
Adjusted EBITDA	$ 79,584	$ 111,901	$ 144,182	$ 195,566

(1) This amount has been reduced by premiums associated with derivatives that settled during the respective periods, which may include premiums accrued but not yet paid as of the end of the quarter based on timing of cash settlement payments with counterparties.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net cash provided by operating activities	$ 62,733	$ 85,604	$ 86,870	$ 149,404
Net change in operating assets and liabilities	(11,833)	(4,627)	5,490	(16,314)
Interest expense, net (1)	29,531	29,502	58,738	58,925

Settlements on commodity derivative contracts, non-cash	(3,347)	1,390	(9,449)	1,269
Loss on inventory market adjustment	—	—	(479)	—
Distributions from equity investments	(101)	—	(101)	—
Earnings from equity investments	2,179	—	2,691	—
Write off of joint venture receivable, non-cash	—	—	—	2,251
Acquisition and divestiture costs included in general and administrative	422	—	422	—
Gain on investment in SPP	—	32	—	32
Adjusted EBITDA	$ 79,584	$ 111,901	$ 144,182	$ 195,566

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

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):

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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 and divestiture costs included in general and administrative;
- Impairment of oil and natural gas properties;
- Certain other items that we deem appropriate; and
- Tax impact of adjustments to net income (loss).

Less:

- Amortization of deferred gain on Western Catarina Midstream Divestiture;
- Preferred stock dividends; and
- Certain other items that we deem appropriate.

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 June 30,	Six Months Ended June 30,

	2016	2015	2016	2015
Net loss	$ (182,868)	$ (562,910)	$ (248,643)	$ (1,060,255)
Less: Preferred stock dividends	(3,987)	(3,991)	(7,974)	(7,982)
Net loss attributable to common shares and participating securities	(186,855)	(566,901)	(256,617)	(1,068,237)
Plus:				
Non-cash write off of joint venture receivables	—	—	—	2,251
Net gains on commodity derivatives contracts	58,750	33,749	35,993	(7,554)
Net settlements received (paid) on commodity derivative contracts (1)	34,720	28,138	87,878	57,493
Impairment of oil and natural gas properties	87,380	468,922	109,464	910,372
Stock-based compensation expense	9,877	7,875	13,222	15,569
Acquisition and divestiture costs included in general and administrative	422		422	—
Amortization of deferred gain on Western Catarina Midstream Divestiture	(3,703)	—	(7,406)	—
Tax impact of adjustments to net income (loss) (2)	—	3,808	—	10,450
Adjusted net income (loss)	591	(24,409)	(17,044)	(79,656)
Adjusted net income (loss) allocable to participating securities	—	—	—	—
Adjusted net income (loss) attributable to common stockholders (3)	$ 591	$ (24,409)	$ (17,044)	$ (79,656)
Weighted average number of shares used to calculate net loss attributable to common stockholders - basic and diluted	58,413	57,184	58,575	56,996

(1) This amount has been reduced by premiums associated with derivatives that settled during the respective periods, which may include premiums accrued but not yet paid as of the end of the quarter based on timing of cash settlement payments with counterparties.

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(2) 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).

(3) The Company's restricted shares of common stock are participating securities.

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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks, 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 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, NGLs and natural gas production. Realized pricing is primarily driven by the prevailing market prices applicable to our oil, NGLs and natural gas production. Pricing for oil, NGLs 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, NGLs 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 OPEC.

To reduce the impact of fluctuations in oil and natural gas prices on the Company's revenues, and to protect the economics of property acquisitions at the time of execution, 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 modify the future prices to be realized. These derivative contracts 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) and collars (whereby the Company receives the excess, if any, of a floating price over a fixed floor price up to a fixed ceiling price). In addition, the Company periodically enters into option and swaption transactions as a way to manage its exposure to fluctuating prices, enhance the value of fixed price swaps, and/or expand the notional quantity hedged under fixed price swaps. 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 June 30, 2016.

At June 30, 2016, the fair value of our commodity derivative contracts was a net asset of approximately $42.2 million. At June 30, 2016, the fair value of the premiums associated with our commodity derivative puts was a liability of approximately $14.4 million. A 10% increase in the oil and natural gas index prices above the June 30, 2016 prices would result in a decrease in the fair value of our commodity derivative contracts of $46.1 million; conversely, a 10% decrease in the oil index price would result in an increase of $46.5 million.

Interest Rate Risk

As of June 30, 2016, 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 June 30, 2016. 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 June 30, 2016. 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, such as borrowings under out Second Amended and Restated Credit Agreement, we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

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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 principal executive officer and principal 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 principal executive officer and principal 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 principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Controls

There was no change in our internal control over financial reporting during the three months ended June 30, 2016 that materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

Item 1. Legal Proceedings

For a description of our material pending legal proceedings, please refer to Note 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 2015 Annual Report, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2015 Annual Report;

and in our other public filings, press releases, and public discussions with our management. Additional risks and uncertainties not currently known to us or that we currently deem immaterial may materially adversely affect our business, financial condition or results of operations.

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.

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Item 6. Exhibits

EXHIBIT INDEX

HIDDEN_ROW

2.1	**	Purchase and Sale Agreement, dated as of July 5, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (filed as Exhibit 2.1 to the Company’s Current Report on Form 8-K on July 6, 2016 (File No. 001-35372) and incorporated herein by reference).
3.1		Certificate of Amendment of Amended and Restated Certificate of Incorporation of Sanchez Energy Corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on May 28, 2013 (File No. 001-35372) 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 (File No. 001-35372) 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 (File No. 001-35372) 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 (File No. 001-35372) and incorporated herein by reference).
4.1	(a)	Instrument of Resignation, Appointment and Acceptance (7.75% Senior Notes), dated as of May 20, 2016, by and among Sanchez Energy Corporation, Delaware Trust Company and U.S. Bank National Association.
4.2	(a)	Instrument of Resignation, Appointment and Acceptance (6.125% Senior Notes), dated as of May 20, 2016, by and among Sanchez Energy Corporation, Delaware Trust Company and U.S. Bank National Association.
10.1	*	Form of Restricted Stock Agreement for Employees (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on April 21, 2016 (File No. 001-35372) and incorporated herein by reference).
10.2	*	Form of Performance Accelerated Restricted Stock Agreement for Employees (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K on April 21, 2016 (File No.

	001-35372) and incorporated herein by reference).
10.3 *	Form of Phantom Stock Agreement for Employees (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on April 21, 2016 (File No. 001-35372) and incorporated herein by reference).
10.4 *	Form of Performance Accelerated Phantom Stock Agreement for Employees (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on April 21, 2016 (File No. 001-35372) and incorporated herein by reference).

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10.5	*	Sanchez Energy Corporation Third Amended and Restated 2011 Long Term Incentive Plan (filed as Exhibit 99.1 to the Company's Current Report on Form 8-K on May 26, 2016 (File No. 001-35372) 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.
101.PRE	(a)	XBRL Taxonomny Extension Presentation Linkbase Document

(a) Filed herewith.

(b) Furnished herewith.

* Management contract or compensatory plan or arrangement.

**The exhibits and schedules to the Purchase and Sale Agreement have been omitted 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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on August 8, 2016.

SANCHEZ ENERGY CORPORATION

By: /s/ Garrick A. Hill
Garrick A. Hill
Interim Chief Financial Officer

(Duly Authorized Officer and Principal Financial Officer)