Sanchez Energy Corp
Form 10-Q
August 07, 2018
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10 Q

(Mark One)

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QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2018
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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer,” “smaller reporting company,” and “emerging growth 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	Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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 3, 2018: 87,797,690

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Sanchez Energy Corporation

Form 10 Q

For the Quarterly Period Ended June 30, 2018

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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," "forecast," "budget," "guidance," "pr "model," "strategy," "future" or their negatives or the statements that include these words or other words that convey the uncertainty of future events or outcomes, are intended to identify forward looking statements, although not all forward looking statements contain such identifying words. In particular, statements, express or implied, concerning our future operating results and returns or our ability to replace or increase reserves, increase production, or generate income or cash flows, operational and commercial benefits of our partnerships, expected benefits from acquisitions, including the Comanche Acquisition (as defined in Note 4, "Acquisitions and Divestitures" of Part I, Item 1. Financial Statements) and our strategic relationship with Sanchez Midstream Partners LP (f/k/a Sanchez Production Partners LP) ("SNMP") 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:

- the timing and extent of changes in prices for, and demand for, crude oil and condensate, natural gas liquids ("NGLs"), natural gas and related commodities;
- our ability to 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 an existing services agreement (the "Services Agreement");
- our ability to replace the reserves we produce through drilling and property acquisitions;
- the realized benefits of the acreage acquired in our various acquisitions, including the Comanche Acquisition, and other assets and liabilities assumed in connection therewith;
- our ability to successfully integrate our various acquired assets into our operations, fully identify existing and potential problems with respect to such assets and accurately estimate reserves, production and costs with respect to

such assets;

- the realized benefits of our partnerships and joint ventures, including our partnership with affiliates of The Blackstone Group, L.P. (“Blackstone”);

- the realized benefits of our transactions with SNMP;

- the extent to which our drilling plans are successful in economically developing our acreage, producing reserves and achieving anticipated production levels;

- 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 creditworthiness and performance of our counterparties, including financial institutions, operating partners and other parties;

- competition in the oil and natural gas exploration and production industry in the marketing of crude oil, natural gas and NGLs and for the acquisition of leases and properties, 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 compete with other companies in the oil and natural gas industry;

- 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 and other funding requirements;

- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;

- 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 and pricing of oil and natural gas;

- 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, the development of alternative energy sources and potential economic implications and other effects therefrom;

- 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

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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. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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GLOSSARY OF SELECTED OIL AND NATURAL GAS TERMS

The following includes a description of the meanings of some of the oil and natural gas industry terms used in this Quarterly Report on Form 10 Q. The definitions “analogous reservoir,” “development costs,” “development project,” “development well,” “economically producible,” “estimated ultimate recoveries,” “exploratory well,” “field,” “possible reserve “probable reserves,” “production costs,” “proved area,” “reservoir,” “resources,” and “unproved properties” have been excerpte from the applicable definitions contained in Rule 4 10(a) of Regulation S X.

American Petroleum Institute (“API”) gravity: A system of classifying oil based on its specific gravity, whereby the greater the gravity, the lighter the oil.

analogous reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

basin: A large depression on the earth’s surface in which sediments accumulate.

Bbl: One stock tank barrel, or 42 U.S. gallons liquid volume, used in reference to oil or other liquid hydrocarbons.

Bcf: One billion cubic feet of natural gas.

black oil: A quality of oil with an API gravity of 15-45° with a gas to oil ratio of 200-900 cubic feet per barrel or less.

Boe: One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Boe of oil.

Boe/d: One Boe per day.

btu: One British thermal unit, the quantity of heat required to raise the temperature of a one pound mass of water by one degree Fahrenheit.

completion: The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

condensate: A liquid hydrocarbon with an API gravity of 50-100°.

developed acreage: The number of acres that are allocated or assignable to producing wells or wells capable of production.

development costs: Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to: (i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves; (ii) drill and equip development wells, development type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly; (iii) acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and (iv) provide improved recovery systems.

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development project: A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

development well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses and taxes.

economically producible: The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

estimated ultimate recoveries: The sum of reserves remaining as of a given date and cumulative production as of that date.

exploitation: A development or other project that may target proven or unproven reserves (such as probable or possible reserves), but that generally has a lower risk than that associated with exploration projects.

exploratory well: A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir.

field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to both the surface and the underground productive formations.

gross acres or gross wells: The total acres or wells, as the case may be, in which we have a working interest.

horizontal drilling: A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

independent exploration and production company: A company whose primary line of business is the exploration and production of crude oil and natural gas.

LLS: Louisiana light sweet crude.

MBbl: One thousand Bbl.

MBoe: One thousand Boe.

Mcf: One thousand cubic feet of natural gas.

MMBbl: One million Bbl.

MMBoe: One million Boe.

MMbtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

net acres or net wells: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

net production: Production that is owned by us less royalties and production due others.

net revenue interest: A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs: The combination of ethane, propane, butane, natural gasolines and other components that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX: New York Mercantile Exchange.

operator: The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

possible reserves: Additional reserves that are less certain to be recovered than probable reserves.

probable reserves: Additional reserves that are less certain to be recovered than proved reserves but that, in sum with proved reserves, are as likely as not to be recovered.

production costs: Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

productive well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

proved area: The part of a property to which proved reserves have been specifically attributed.

proved developed reserves: Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

proved developed non-producing reserves: Reserves that are expected to be recovered from completion intervals which are open at the time of the estimate but which have not yet started producing, wells which were shut-in for market conditions or pipeline connections, or wells not capable of production for mechanical reasons; reserves that are expected to be recovered from zones in existing well which will require additional completion work or future re-completion prior to start production.

proved oil and natural gas reserves: The estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

proved undeveloped reserves: Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

realized price: The cash market price less all expected quality, transportation and demand adjustments.

recompletion: The action of reentering an existing wellbore to redo or repair the original completion in order to increase the well’s productivity.

reserve: That part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination.

reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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resources: Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

spacing: The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres (e.g., 75 acre well-spacing) and is often established by regulatory agencies.

standardized measure: The present value of estimated future after tax net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions.

trend: A geographic area with hydrocarbon potential.

undeveloped acreage: Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

unproved properties: Properties with no proved reserves.

volatile oil: A quality of oil with an API gravity of 42-55° with a gas to oil ratio of 900-3,500 cubic feet per barrel.

wellbore: The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole.

working interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

workover: Operations on a producing well to restore or increase production.

WTI: West Texas Intermediate crude.

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PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

Sanchez Energy Corporation

Condensed Consolidated Balance Sheets (Unaudited)

(in thousands, except par value and share amounts)

	June 30, 2018	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 437,689	$ 184,434
Oil and natural gas receivables	88,207	101,396
Joint interest billings receivables	15,793	22,569
Accounts receivable - related entities	6,192	4,491
Fair value of derivative instruments	3,241	16,430
Other current assets	10,877	21,478
Total current assets	561,999	350,798
Oil and natural gas properties, on the basis of successful efforts accounting:		
Proved oil and natural gas properties	3,418,554	3,130,407
Unproved oil and natural gas properties	434,244	398,605
Total oil and natural gas properties	3,852,798	3,529,012
Less: Accumulated depreciation, depletion, amortization and impairment	(1,618,850)	(1,501,553)
Total oil and natural gas properties, net	2,233,948	2,027,459
Other assets:		
Fair value of derivative instruments	8,836	1,428
Investments (Investment in SNMP measured at fair value of $26.8 million and $25.2 as of June 30, 2018 and December 31, 2017, respectively)	46,758	38,462
Other assets	52,873	52,488
Total assets	$ 2,904,414	$ 2,470,635
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 15,446	$ 14,994
Other payables	100,451	81,970
Accrued liabilities:		
Capital expenditures	93,506	85,340

Other	96,036	84,794
Fair value of derivative instruments	102,904	56,190
Short term debt	23,996	23,996
Other current liabilities	71,107	115,244
Total current liabilities	503,446	462,528
Long term debt, net of premium, discount and debt issuance costs	2,364,749	1,930,683
Asset retirement obligations	38,499	36,098
Fair value of derivative instruments	31,132	17,474
Other liabilities	34,332	65,480
Total liabilities	2,972,158	2,512,263
Commitments and contingencies (Note 17)		
Mezzanine equity:		
Preferred units ($1,000 liquidation preference, 500,000 units authorized, issued and outstanding as of June 30, 2018 and December 31, 2017)	452,131	427,512
Stockholders' deficit:		
Preferred stock ($0.01 par value, 15,000,000 shares authorized; 1,838,985 shares issued and outstanding as of June 30, 2018 and December 31, 2017 of 4.875% Convertible Perpetual Preferred Stock, Series A; 3,527,830 shares issued and outstanding as of June 30, 2018 and December 31, 2017 of 6.500% Convertible Perpetual Preferred Stock, Series B)	53	53
Common stock ($0.01 par value, 300,000,000 shares authorized; 87,797,689 and 83,984,827 shares issued and outstanding as of June 30, 2018 and December 31, 2017, respectively)	884	845
Additional paid-in capital	1,370,908	1,362,118
Accumulated deficit	(1,891,720)	(1,832,156)
Total stockholders' deficit	(519,875)	(469,140)
Total liabilities and stockholders' deficit	$ 2,904,414	$ 2,470,635

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,	
	2018	2017*	2018	2017*
REVENUES:				
Oil sales	$ 156,544	$ 91,096	$ 311,935	$ 164,372
Natural gas liquid sales	56,533	36,873	105,838	63,973
Natural gas sales	41,141	47,735	82,870	81,201
Sales and marketing revenues	5,096	—	9,897	—
Total revenues	259,314	175,704	510,540	309,546
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	77,644	62,620	149,592	100,620
Exploration expenses	516	4,446	549	4,797
Sales and marketing expenses	5,086	—	9,259	—
Production and ad valorem taxes	14,208	8,799	27,677	15,323
Depreciation, depletion, amortization and accretion	62,323	40,842	121,571	67,245
Impairment of oil and natural gas properties	194	—	1,142	1,845
General and administrative expenses	29,467	29,713	51,887	97,178
Total operating costs and expenses	189,438	146,420	361,677	287,008
Operating income	69,876	29,284	148,863	22,538
Other income (expense):				
Interest income	1,528	150	2,270	507
Other income (expense)	6,715	(6,618)	10,143	3,917
Gain on sale of oil and natural gas properties	1,528	6,022	1,528	10,366
Interest expense	(44,590)	(35,961)	(88,510)	(68,986)
Earnings from equity investments	—	242	—	677
Net gains (losses) on commodity derivatives	(70,044)	59,614	(114,098)	98,496
Total other income (expense)	(104,863)	23,449	(188,667)	44,977
Income (loss) before income taxes	(34,987)	52,733	(39,804)	67,515
Income tax benefit	—	255	—	1,208
Net income (loss)	(34,987)	52,988	(39,804)	68,723
Less:				
Preferred stock dividends	(3,987)	(3,987)	(7,974)	(7,974)
Preferred unit dividends and distributions	(12,500)	(10,950)	(22,408)	(27,415)
Preferred unit amortization	(6,189)	(5,282)	(12,119)	(6,992)
Net income allocable to participating securities	—	(2,378)	—	(1,974)
Net income (loss) attributable to common stockholders	$ (57,663)	$ 30,391	$ (82,305)	$ 24,368

Net income (loss) per common share - basic	$ (0.71)	$ 0.40	$ (1.01)	$ 0.33
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders - basic	81,787	76,395	81,356	73,045
Net income (loss) per common share - diluted	$ (0.71)	$ 0.39	$ (1.01)	$ 0.33
Weighted average number of shares used to calculate net income (loss) attributable to common stockholders - diluted	81,787	89,015	81,356	73,145

*Financial information for 2017 has been recast to reflect retrospective application of the successful efforts method of accounting. See Note 3.

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' Deficit for the Six Months Ended June 30, 2018 (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, 2017	1,839	$ 18	3,528	$ 35	83,985	$ 845	$ 1,362,118	$ (1,832,156)	$ (469,140)
Adoption of accounting standards	—	—	—	—	—	—	—	22,739	22,739
Issuance of common stock	—	—	—	—	100	1	567	—	568
Dividends on Series A and Series B Preferred stock	—	—	—	—	805	8	3,977	(7,972)	(3,987)
Dividends on SN UnSub preferred units	—	—	—	—	—	—	—	(25,000)	(25,000)
Distributions - SN UnSub preferred units	—	—	—	—	—	—	—	2,592	2,592
Accretion of discount on SN UnSub preferred units	—	—	—	—	—	—	—	(12,119)	(12,119)
Restricted stock awards, net of forfeitures	—	—	—	—	2,908	30	(30)	—	—
Non-cash stock-based compensation	—	—	—	—	—	—	4,276	—	4,276
Net loss	—	—	—	—	—	—	—	(39,804)	(39,804)
BALANCE, June 30, 2018	1,839	$ 18	3,528	$ 35	87,798	$ 884	$ 1,370,908	$ (1,891,720)	$ (519,875)

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

Sanchez Energy Corporation

Condensed Consolidated Statements of Cash Flows (Unaudited)

(in thousands)

	Six Months Ended June 30, 2018	2017*
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (39,804)	$ 68,723
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion	121,571	67,245
Impairment of oil and natural gas properties	1,142	1,845
Gain on sale of oil and natural gas properties	(1,528)	(10,366)
Stock-based compensation expense	8,395	30,391
Net (gains) losses on commodity derivative contracts	114,098	(98,496)
Net cash settlements received (paid) on commodity derivative contracts	(39,306)	4,069
(Gain) loss on other derivatives	4,526	(249)
Gain on investments	(8,296)	(806)
Amortization of deferred gain on Western Catarina Midstream Divestiture	(11,860)	(11,860)
Amortization of debt issuance costs	9,832	6,205
Accretion of debt discount, net	697	316
Deferred taxes	—	(1,208)
Gain on inventory market adjustment	—	(9)
Loss from equity investments	—	847
Distributions from equity investments	—	(677)
Changes in operating assets and liabilities:		
Accounts receivable	15,314	(50,521)
Accounts receivable - related entities	(1,701)	710
Other payables	11,832	816
Accrued liabilities	16,531	6,992
Other current liabilities	(51,203)	42,656
Other assets and liabilities, net	5,054	3,138
Net cash provided by operating activities	155,294	59,761
CASH FLOWS FROM INVESTING ACTIVITIES:		
Payments for oil and natural gas properties	(307,665)	(212,883)
Payments for other property and equipment	(1,237)	(15,130)
Proceeds from sale of oil and natural gas properties	1,425	60,802
Acquisition of oil and natural gas properties	2,834	(1,039,127)
Proceeds from sale of inventory	158	—
Payments for investments	—	(74)
Payments for purchases of inventory	(2,473)	—
Sale of investments	—	12,500
Net cash used in investing activities	(306,958)	(1,193,912)

CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	539,865	258,500
Repayment of borrowings	(103,174)	(60,000)
Issuance of common stock	—	135,942
Issuance of preferred units	—	500,000
Issuance costs related to preferred units	—	(20,894)
Financing costs	(13,208)	(24,633)
Preferred dividends paid	(7,974)	—
Cash paid to tax authority for employee stock-based compensation awards	(682)	(1,019)
Preferred unit distribution	(9,908)	(27,415)
Net cash provided by financing activities	404,919	760,481
Increase (decrease) in cash and cash equivalents	253,255	(373,670)
Cash and cash equivalents, beginning of period	184,434	501,917
Cash and cash equivalents, end of period	$ 437,689	$ 128,247
NON-CASH INVESTING AND FINANCING ACTIVITIES:		
Change in asset retirement obligations	$ 860	$ 5,521
Change in accrued capital expenditures	8,166	61,735
SUPPLEMENTAL DISCLOSURE:		
Cash paid for interest	$ 63,658	$ 61,786

* Financial information for 2017 has been recast to reflect retrospective application of the successful efforts method of accounting. See Note 3.

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 and Business

Sanchez Energy Corporation (together with our consolidated subsidiaries, "Sanchez Energy," the "Company," "SN," "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 U.S. onshore unconventional oil and natural gas resources, with a current focus on the horizontal development of significant resource potential from the Eagle Ford Shale in South Texas. We also hold an undeveloped acreage position in the Tuscaloosa Marine Shale ("TMS") in Mississippi and Louisiana, which offers potential future development opportunities. As of June 30, 2018, we have assembled approximately 485,000 gross leasehold acres (283,000 net acres) in the Eagle Ford Shale. In addition, we continually evaluate opportunities to grow our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on the opportunities and the financing alternatives available to us at the time we consider such opportunities. We have included definitions of some of the oil and natural gas terms used in this Quarterly Report on Form 10-Q in the "Glossary of Selected Oil and Natural Gas Terms."

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, 2017 from the audited financial statements filed in its Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (the "2017 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 2017 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, 2018, 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 2017 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 accompanying 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 proved oil and natural gas properties, the evaluation of unproved properties for impairment, the fair value of commodity derivative contracts, embedded derivatives and asset retirement obligations, accrued oil and natural gas revenues, capital expenditures and expenses and the allocation of general and administrative (“G&A”) expenses. Actual results could differ materially from those estimates.

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Recent Accounting Pronouncements

In June 2018, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2018-07 “Compensation - Stock Compensation (ASC 718) - Improvements to Nonemployee Share-Based Payment Accounting,” which expands the scope of ASC 718, Compensation – Stock Compensation, to include share-based payment transactions for acquiring goods and services from nonemployees. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2018. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

In August 2017, the FASB issued ASU 2017-12 “Derivatives and Hedging (ASC 815): Targeted Improvements to Accounting for Hedging Activities,” which changes the recognition and presentation requirements of hedge accounting, including eliminating the requirement to separately measure and report hedge ineffectiveness, and presenting all items that affect earnings in the same income statement line item as the hedged item. The ASU also provides new alternatives for applying hedge accounting. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2018. The Company is currently in the process of evaluating the impact of adoption of this guidance on its consolidated financial statements.

In January 2017, the FASB issued ASU 2017-01 “Business Combinations (ASC 805): Clarifying the Definition of a Business,” which provides a new framework for determining whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. This ASU is now effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The Company adopted this ASU on January 1, 2018, using a prospective method; the clarified definition of a business will be applied by the Company to transactions executed subsequent to the effective date.

In November 2016, the FASB issued ASU 2016-18 “Statement of Cash Flows (ASC 230): Restricted Cash,” which requires companies to include cash and cash equivalents that have restrictions on withdrawal or use in total cash and cash equivalents on the statement of cash flows. This ASU is now effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The adoption of ASU 2016-18 did not have an impact on the Company’s unaudited condensed consolidated statement of cash flows.

In October 2016, the FASB issued ASU 2016-16 “Income Taxes (ASC 740): Intra-Entity Transfers of Assets Other Than Inventory,” which eliminates a current exception in U.S. GAAP to the recognition of the income tax effects of temporary differences that result from intra-entity transfers of non-inventory assets. The intra-entity exception is being eliminated under the ASU. The standard is required to be applied on a modified retrospective basis and is now effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2017. The adoption of ASU 2016-16 did not have an impact on the Company’s unaudited condensed consolidated financial statements and related disclosures.

In August 2016, the FASB issued ASU 2016-15 “Statement of Cash Flows (ASC 230): Classification of Certain Cash Receipts and Cash Payments”. This ASU is intended to clarify the presentation of cash receipts and payments in specific situations. The amendments in this ASU are now effective for financial statements issued for annual periods beginning after December 15, 2017. The Company adopted this ASU on January 1, 2018, using a retrospective method. The adoption of ASU 2016-15 did not have an impact on the Company’s unaudited condensed consolidated statement of cash flows.

In February 2016, the FASB issued ASU 2016-02 “Leases (ASC 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. Additionally in July 2018, the FASB issued ASU 2018-10, "Codification Improvements to Topic 842 (Leases),” which provides narrow amendments to clarify how to apply certain aspects of ASU 2016-02. The effective date in ASU 2018-10 is the same as that of ASU 2016-02. The standards update the previous lease guidance by requiring the recognition of a right-to-use asset and lease liability on the statement of financial position for all leases with lease terms of more than 12 months. The lease liability represents the discounted obligation to make future minimum lease payments and corresponding right-of-use asset on the balance sheet for most leases. Recognition, measurement and presentation of expenses and cash flows arising from a lease will depend on classification as a finance or operating lease. The Company has several operating leases as further discussed in Note 17, “Commitments and Contingencies,” which will be impacted by the new rules under this standard. The Company will not early adopt this standard, and will apply the revised lease rules for our interim and annual reporting periods starting January 1, 2019. The Company is currently

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evaluating the impact of these rules on its financial statements and has started the assessment process by evaluating the population of leases under the revised definition. The Company is also in the process of implementing a lease accounting software to properly account for lease data upon adoption. The adoption of this standard will result in an increase in the assets and liabilities on the Company's condensed consolidated balance sheets. The quantitative impacts of the new standard are dependent on the active leases at the time of adoption. As a result, the evaluation of the effect of the new standards will extend over future periods.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (ASC 606)." In March, April, May and December of 2016, the FASB issued rules clarifying several aspects of the new revenue recognition standard. The new guidance is effective for fiscal years and interim periods beginning after December 15, 2017. 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 standard also requires more detailed disclosures related to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. See Note 18, "Revenue Recognition" for discussion of the Company's adoption of the new standard.

Note 3. Change in Accounting Principle

During the fourth quarter of 2017, the Company voluntarily changed its method of accounting for oil and natural gas exploration and development activities from the full cost method to the successful efforts method. Accordingly, financial information for prior periods has been recast to reflect retrospective application of the successful efforts method. In general, under successful efforts, exploration expenditures such as exploratory dry holes, exploratory geological and geophysical costs, delay rentals, unproved impairments, and exploration overhead are charged against earnings as incurred, versus being capitalized under the full cost method of accounting. The successful efforts method also provides for the assessment of potential property impairments under FASB Accounting Standards Codification (ASC) 360 "Property, Plant and Equipment" by comparing the net carrying value of oil and natural gas properties with associated projected undiscounted pre-tax future net cash flows. If the expected undiscounted pre-tax future net cash flows are lower than the unamortized capitalized costs, the capitalized cost is reduced to fair value. Under the full cost method of accounting, a write-down would be required if the net carrying value of oil and natural gas properties exceeds a full cost "ceiling," using an unweighted arithmetic average of commodity prices in effect on the first day of each of the previous 12 months. In addition, gains or losses, if applicable, are generally recognized on the dispositions of oil and natural gas property and equipment under the successful efforts method, as opposed to an adjustment to the net carrying value of the remaining assets under the full cost method unless the sale or disposition does not cause a significant change in the relationship between costs and the estimated quantities of proved reserves. Our consolidated financial statements have been recast to reflect these differences for all periods presented, including the Condensed Consolidated Balance Sheets, Condensed Consolidated Statements of Operations, Condensed Consolidated Statements of Stockholders' Deficit, Condensed Consolidated Statements of Cash Flows and related information in Notes 3, 4, 6, 12, 13, 14, 16 and 19.

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The following table presents the effects of the change to the successful efforts method in the condensed consolidated balance sheet as of June 30, 2017 (in thousands):

	Changes to Condensed Consolidated Balance Sheet		
June 30, 2017	Under Full Cost	Changes	As Reported Under Successful Efforts
Oil and natural gas properties:			
Proved oil and natural gas properties	$ 4,186,528	$ (1,360,068)	$ 2,826,460
Unproved oil and natural gas properties	477,863	(8,497)	469,366
Total oil and natural gas properties	4,664,391	(1,368,565)	3,295,826
Less: Accumulated depreciation, depletion, amortization and impairment	(2,818,705)	1,423,768	(1,394,937)
Total oil and natural gas properties, net	1,845,686	55,203	1,900,889
Other assets	41,604	(1,014)	40,590
Total assets	$ 2,218,053	$ 54,189	$ 2,272,242
Current liabilities:			
Other current liabilities	$ 79,362	$ 8,907	$ 88,269
Total current liabilities	272,861	8,907	281,768
Other liabilities	56,387	20,412	76,799
Total liabilities	2,256,191	29,319	2,285,510
Accumulated deficit	(1,795,631)	24,870	(1,770,761)
Total stockholders' deficit	(447,323)	24,870	(422,453)
Total liabilities and stockholders' deficit	$ 2,218,053	$ 54,189	$ 2,272,242

The following table presents the effects of the change to the successful efforts method in the condensed consolidated statement of operations for the three and six months ended June 30, 2017 (in thousands, except per share amounts):

	Changes to the Condensed Consolidated Statement of Operations		
For the three months ended June 30, 2017	Under Full Cost	Changes	As Reported Under Successful Efforts
Oil and natural gas production expenses	$ 64,848	$ (2,228)	$ 62,620
Exploration expenses	—	4,446	4,446
Depreciation, depletion, amortization and accretion	50,851	(10,009)	40,842
Impairment of oil and natural gas properties	—	—	—

Gain on sale of oil and natural gas properties	7,133	(1,111)	6,022
Net income	46,309	6,679	52,988
Net income allocable to participating securities	(1,893)	(485)	(2,378)
Net income attributable to common stockholders	$ 24,198	$ 6,193	$ 30,391
Net income per common share - basic	$ 0.32	$ 0.08	$ 0.40
Net income per common share - diluted	$ 0.31	$ 0.08	$ 0.39

	Changes to the Condensed Consolidated Statement of Operations		
For the six months ended June 30, 2017	Under Full Cost	Changes	As Reported Under Successful Efforts
Oil and natural gas production expenses	$ 105,073	$ (4,453)	$ 100,620
Exploration expenses	—	4,797	4,797
Depreciation, depletion, amortization and accretion	84,057	(16,812)	67,245
Impairment of oil and natural gas properties	—	1,845	1,845
Gain on sale of oil and natural gas properties	12,276	(1,910)	10,366
Net income	56,010	12,713	68,723
Net income allocable to participating securities	(1,021)	(953)	(1,974)
Net income attributable to common stockholders	$ 12,608	$ 11,760	$ 24,368
Net income per common share - basic	$ 0.17	$ 0.16	$ 0.33
Net income per common share - diluted	$ 0.17	$ 0.16	$ 0.33

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The following table presents the effects of the change to the successful efforts method in the condensed consolidated statement of cash flows for the six months ended June 30, 2017 (in thousands):

	Changes to the Condensed Consolidated Statement of Cash Flows		
For the six months ended June 30, 2017	Under Full Cost	Change	As Reported Under Successful Efforts
Net income	$ 56,010	$ 12,713	$ 68,723
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	84,057	(16,812)	67,245
Impairment of oil and natural gas properties	—	1,845	1,845
Gain on sale of oil and natural gas properties	(12,276)	1,910	(10,366)
Amortization of deferred gain on Catarina Midstream Sale	(7,407)	(4,453)	(11,860)
Net cash provided by operating activities	64,558	(4,797)	59,761
Payments for oil and natural gas properties	(217,680)	4,797	(212,883)
Net cash used in investing activities	(1,198,709)	4,797	(1,193,912)
Net cash provided by financing activities	760,481	—	760,481
Decrease in cash and cash equivalents	(373,670)	—	(373,670)
Cash and cash equivalents, beginning of period	501,917	—	501,917
Cash and cash equivalents, end of period	$ 128,247	$ —	$ 128,247

Note 4. Acquisitions and Divestitures

Our acquisitions are accounted for under the acquisition method of accounting in accordance with ASC 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.

Typically, the sale or disposition of oil and natural gas properties results in a gain or loss being recorded as the difference between the proceeds received and the net capitalized costs of the oil and natural gas properties, unless the sale or disposition does not cause a significant change in the relationship between costs and the estimated quantities of proved reserves. In circumstances where treating a sale like a normal retirement does not result in a significant change in the relationship between costs and the estimated quantities of proved reserves, the proceeds are applied to reduce net capitalized costs.

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Javelina Disposition

On September 19, 2017, the Company, through its wholly owned subsidiary, SN Cotulla Assets, LLC (“SN Cotulla”), sold approximately 68,000 undeveloped net acres located in the Eagle Ford Shale in LaSalle and Webb Counties, Texas to Vitruvian Exploration IV, LLC for approximately $105 million in cash, after preliminary closing adjustments (the “Javelina Disposition”). Consideration received from the Javelina Disposition was based on an August 1, 2017 effective date. The Company recorded a gain of approximately $73.7 million on the Javelina Disposition.

Marquis Disposition

On June 15, 2017, the Company, through its wholly owned subsidiary, SN Marquis LLC, sold approximately 21,000 net acres primarily located in the Eagle Ford Shale in Fayette and Lavaca Counties, Texas to Lonestar Resources US, Inc. (“Lonestar”) for an adjusted purchase price of approximately $44 million in cash and approximately $6.0 million in Lonestar’s Series B Convertible Preferred Stock, valued as of the closing date, which subsequently converted into 1.5 million shares of Lonestar’s Class A Common Stock (the “Marquis Disposition”). The consideration received from the Marquis Disposition was based on a January 1, 2017 effective date. Assets conveyed pursuant to the Marquis Disposition consisted of net proved reserves of approximately 2.7 MMBoe (100% developed) and net production of approximately 1,750 Boe per day from 104 gross (65 net) wells. The Company did not record any gains or losses as a result of the Marquis Disposition.

Comanche Acquisition

On March 1, 2017, the Company, through two of its subsidiaries, SN EF UnSub, LP (“SN UnSub”) and SN EF Maverick, LLC (“SN Maverick”), along with Gavilan Resources, LLC (“Gavilan”), an entity controlled by Blackstone, completed the acquisition of approximately 318,000 gross (155,000 net) acres comprised of 252,000 gross (122,000 net) Eagle Ford Shale acres and 66,000 gross (33,000 net) acres of deep rights only, which includes the Pearsall Shale, representing an approximate 49% average working interest therein (the “Comanche Assets”) from Anadarko E&P Onshore LLC and Kerr-McGee Oil and Gas Onshore LP (together, “Anadarko”) for approximately $2.1 billion in cash (the “Comanche Acquisition”). Pursuant to the purchase and sale agreement entered into in connection with the Comanche Acquisition, (i) SN UnSub paid approximately 37% of the purchase price (including a $100 million cash contribution from other Company entities) and (ii) SN Maverick paid approximately 13% of the purchase price. In the aggregate, SN UnSub and SN Maverick acquired half of the 49% working interest in the Comanche Assets (approximately 50% and 0%, respectively, of the estimated total proved developed producing reserves (PDPs), 20% and 30%, respectively, of the estimated total proved developed non-producing reserves (PDNPs), and 20% and 30%, respectively, of the total proved undeveloped reserves (PUDs)) (“SN Comanche Assets”). Pursuant to the purchase and sale agreement, Gavilan paid 50% of the purchase price and acquired the remaining half of the 49% working interest in the Comanche Assets (and approximately 50% of the estimated total PDPs, PDNPs and PUDs). The Comanche Assets are primarily located in the Western Eagle Ford and are contiguous with our existing acreage, significantly expanding our asset base and production. The effective date of the Comanche Acquisition was July 1, 2016. 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	$ 781,789
Unproved properties	263,471
Other assets acquired	6,702
Fair value of assets acquired	1,051,962
Asset retirement obligations	(8,289)
Fair value of net assets acquired	$ 1,043,673

Cotulla Disposition

On December 14, 2016, SN Cotulla Assets, LLC ("SN Cotulla"), a wholly-owned subsidiary of the Company, completed the initial closing of the sale of certain oil and natural gas interests and associated assets located in Dimmit, Frio, LaSalle, Zavala and McMullen Counties, Texas (the "Cotulla Assets") to Carrizo (Eagle Ford) LLC ("Carrizo Eagle Ford") pursuant to a purchase and sale agreement dated October 24, 2016 by and among SN Cotulla, the Company for the limited purposes set forth therein, Carrizo Eagle Ford and Carrizo Oil and Gas for the limited purposes set forth therein, for an adjusted purchase price of approximately $153.5 million, subject to normal and customary post-closing

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adjustments (the “Cotulla Disposition”). The assets sold included estimated net proved reserves as of the effective date of June 1, 2016 of approximately 6.9 MMBoe. Proved developed reserves were estimated to account for approximately 90% of the total net proved reserves. As of the effective date, the Cotulla Assets consisted of approximately 15,000 net acres with 112 gross (93 net) wells producing approximately 3,000 Boe/d. During 2017, two additional closings occurred and final settlement adjustments were made resulting in total aggregate consideration of approximately $167.4 million. The Company determined that adjustments to capitalized costs for the Cotulla Disposition would cause a significant change in the relationship between costs and the estimated quantities of proved reserves. Upon the initial closing of the Cotulla Disposition, the Company recorded a gain of approximately $85.3 million. As a result of subsequent closings of the Cotulla Disposition, the Company recorded additional gains of $4.3 million and $6.0 million during the three months ended March 31, 2017 and June 30, 2017, respectively.

Note 5. Cash and Cash Equivalents

As of June 30, 2018 and December 31, 2017, cash and cash equivalents consisted of the following (in thousands):

	June 30, 2018	December 31, 2017
Cash	$ 80,046	$ 135,363
Cash equivalents	357,643	49,071
Total cash and cash equivalents	$ 437,689	$ 184,434

Note 6. Oil and Natural Gas Properties

The Company’s oil and natural gas properties are accounted for using the successful efforts method of accounting. All direct costs and certain indirect costs associated with the acquisition, successful 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. The sale or disposition of oil and natural gas properties results in a gain or loss unless the sale or disposition does not cause a significant change in the relationship between costs and the estimated quantities of proved reserves in which case the proceeds are applied to reduce net capitalized costs.

Depreciation, depletion and amortization—Depreciation, depletion and amortization (“DD&A”) is provided using the units of production method based upon estimates of proved reserves of oil, natural gas and NGLs and conversion of production of the same to a common unit of measure based upon the relative energy content of each hydrocarbon. The

Company groups its oil and natural gas properties with a common geological structure or stratigraphic condition ("common operating field") in accordance with ASC 932 "Extractive Activities – Oil and Gas" for purposes of computing DD&A, assessing proved property impairments and accounting for asset dispositions. All capitalized costs of oil and natural gas properties are amortized using the units of production method based on proved reserves. Investments in unproved properties and major development projects are not amortized until proved reserves associated with the projects can be determined. Once the assessment of unproved properties is complete and when major development projects are evaluated, the costs previously excluded from the amortization base are transferred to proved oil and natural gas properties and amortization begins. All other non-oil and natural gas assets are stated at historical cost, net of impairments, and are depreciated using the straight-line method over their respective useful lives.

In arriving at depletion rates under the units of production method, the quantities of recoverable oil and natural gas reserves are established based on estimates made by internal and third-party geologists and engineers, which require significant judgment as does the projection of future production volumes and levels of future costs. In addition, considerable judgment is necessary in determining the existence of proved reserves once a well has been drilled. All of these judgments may have significant impact on the calculation of depletion expense.

Impairment of Oil and Natural Gas Properties —Capitalized costs (net of accumulated DD&A and impairment) of proved oil and natural gas properties are subjected to an impairment test when facts and circumstances indicate that their carrying value may not be recoverable. We compare net capitalized costs of proved oil and natural gas properties to estimated undiscounted future net cash flows using management's expectations of future oil and natural gas prices. These future price scenarios reflect our estimation of future price volatility. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, using estimated discounted future net cash flows. Significant inputs used to determine the fair values of proved properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital rate. The underlying commodity prices embedded in the estimated cash flows are the product of a process that begins with NYMEX forward curve pricing, adjusted for estimated location and quality differentials, as well as other factors that management believes will impact realizable prices of our oil and natural gas properties. We did not record a proved property impairment during the three and six month periods ended June 30, 2018 and 2017. Changes in production rates, levels of reserves, future development costs, and other factors will impact our actual impairment analyses in future periods.

Unproved Properties—Costs associated with unproved properties and properties under development are excluded from the amortization base until the properties have been evaluated. Additionally, the costs associated with leasehold acreage and wells currently drilling are also initially excluded from the amortization base. 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 transferred into the amortization base when management determines that a project area has been evaluated through drilling operations or thorough geologic evaluation. If the results of an assessment indicate that the properties are impaired, the carrying amount of the identified unproved properties are reduced to their fair value. We recorded $0.2 million and $1.1 million of impairment to our unproved oil and natural gas properties for the three and six months ended June 30, 2018, respectively, and we recorded no impairment and $1.8 million of impairment to our unproved oil and natural gas properties for the three and six months ended June 30, 2017, respectively.

Note 7. Debt

Debt as of June 30, 2018 consisted of (i) $167.5 million under the SN UnSub Credit Agreement (as defined below), which is non-recourse to SN and the other obligors under the 6.125% Notes (defined below), 7.75% Notes (defined below), 7.25% Senior Secured Notes (defined below) and the Credit Agreement (defined below) (“Non-Recourse to the Company”), as well as to the obligors under the SR Credit Agreement (defined below) and the Non-Recourse Subsidiary Term Loan (defined below), (ii) $600 million principal amount of 7.75% Notes maturing on June 15, 2021, (iii) approximately $4 million related to a 4.59% non-recourse subsidiary term loan due 2022 (the “Non-Recourse Subsidiary Term Loan”), which is Non-Recourse to the Company and to the obligors under the SN UnSub Credit Agreement and the SR Credit Agreement, (iv) $1.15 billion principal amount of 6.125% Notes maturing on January 15, 2023, (v) $500 million principal amount of 7.25% Senior Secured Notes maturing on February 15, 2023, subject to satisfaction of certain conditions, and (vi) approximately $24.0 million under the SR Credit Agreement, which is Non-Recourse to the Company and to the obligors under the SN UnSub Credit Agreement and the Non-Recourse Subsidiary Term Loan.

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As of June 30, 2018 and December 31, 2017, the Company's outstanding debt consisted of the following (in thousands):

	Interest Rate	Original Maturity Date	June 30, 2018	December 31, 2017
Short-Term Debt				
SR Credit Agreement(1)(2)	Variable	August 8, 2018	$ 23,996	$ 23,996
Total short-term debt			$ 23,996	$ 23,996
Long-Term Debt				
Credit Agreement	Variable	February 14, 2023	$ —	$ 50,000
SN UnSub Credit Agreement(1)	Variable	March 1, 2022	167,500	175,500
7.75% Notes	7.75%	June 15, 2021	600,000	600,000
4.59% Non-Recourse Subsidiary Term Loan(1)	4.59%	August 31, 2022	3,990	4,164
6.125% Notes	6.125%	January 15, 2023	1,150,000	1,150,000
7.25% Senior Secured Notes	7.25%	February 15, 2023	500,000	—
			2,421,490	1,979,664
Unamortized discount on Additional 7.75% Notes			(2,674)	(3,126)
Unamortized premium on Additional 6.125% Notes			1,225	1,360
Unamortized discount on 7.25% Senior Secured Notes			(4,755)	—
Unamortized debt issuance costs			(50,537)	(47,215)
Total long-term debt			$ 2,364,749	$ 1,930,683

(1) These debt instruments are Non-Recourse to the Company.
(2) Bears a weighted-average interest rate of 6.522% and 5.122% for the six months ended June 30, 2018 and one month ended December 31, 2017, respectively.

The components of interest expense are as follows (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Interest on SR Credit Agreement	$ (480)	$ —	$ (828)	$ —
Interest and commitment fees on Credit Agreement	(30)	(562)	(695)	(940)

Interest on SN UnSub Credit Agreement	(2,202)	(2,299)	(4,503)	(3,055)
Interest on Senior Notes	(38,297)	(29,234)	(71,861)	(58,470)
Interest on Non-Recourse Subsidiary Term Loan	(47)	—	(94)	—
Amortization of debt issuance costs	(3,118)	(3,708)	(9,832)	(6,205)
Amortization of discounts and premium on Senior Notes	(416)	(158)	(697)	(316)
Total interest expense	$ (44,590)	$ (35,961)	$ (88,510)	$ (68,986)

Credit Facilities

Third Amended and Restated Credit Agreement

On February 14, 2018, the Company, as borrower, and its existing restricted subsidiaries, as loan parties (the "Loan Parties"), entered into a revolving credit facility represented by a Third Amended and Restated Credit Agreement dated as of February 14, 2018 with Royal Bank of Canada, providing for a $25 million first-out senior secured working capital and letter of credit facility (the "Credit Agreement"), which amended and restated the Company's previous credit facility in its entirety. Although pari passu in right of payment with the 7.25% Senior Secured Notes, the obligations under our amended and restated credit facility and specified hedging and cash management obligations have, pursuant to the terms of a collateral trust agreement, "first-out" status as to proceeds of the shared collateral and thus the 7.25% Senior Secured Notes are, to the extent of the value of the collateral, effectively junior to the obligations under our amended and restated credit facility and such specified hedging and cash management obligations. Availability under the

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Credit Agreement is at all times subject to customary conditions but, except in limited circumstances, not to satisfaction of any collateral coverage ratio or other maintenance covenants. As of June 30, 2018, there were no borrowings and no letters of credit outstanding under the Credit Agreement.

The Credit Agreement will mature on the earlier of (i) February 14, 2023 or (ii) the 91st day prior to the scheduled maturity of any "material indebtedness," which is defined to include, without limitation, any indebtedness arising in connection with the Company's 7.75% Notes, 6.125% Notes or the 7.25% Senior Secured Notes. The 7.75% Notes are scheduled to mature on June 15, 2021.

The Company's obligations under the Credit Agreement are guaranteed by all of the Company's restricted subsidiaries that guarantee the 7.25% Senior Secured Notes and, pursuant to the CTA (as defined below), are secured by priority liens on a first-out collateral proceeds payment priority basis in the Shared Collateral (as defined below), subject only to permitted collateral liens.

At the Company's election, interest on borrowings under the Credit Agreement may be calculated based on an ABR or an adjusted Eurodollar (LIBOR) rate, plus an applicable margin. The applicable margin is either 1.50% or 2.25% for ABR borrowings and either 2.50% or 3.25% for Eurodollar (LIBOR) borrowings and letters of credit, if any, depending on the Company's utilization of the availability under the Credit Agreement. The Company is also required to pay a commitment fee of 0.50% per annum on any unused commitment amount. Interest on ABR borrowings and the commitment fee are generally payable quarterly. Interest on Eurodollar borrowings are generally payable at the end of the applicable interest period.

The Credit Agreement contains various affirmative and negative covenants and events of default that limit the Company's ability to, among other things, incur indebtedness, make restricted payments, grant liens and consolidate or merge. The Credit Agreement also provides for cross default between the Credit Agreement and the other material indebtedness of the Company and its restricted subsidiaries, in an aggregate principal amount in excess of $40 million. As of June 30, 2018, the Company was in compliance with the covenants of the Credit Agreement.

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

SN UnSub Credit Agreement

On March 1, 2017, SN UnSub, as borrower, entered into a credit agreement for a $500 million revolving credit facility with JP Morgan Chase Bank, N.A. as the administrative agent and the lenders party thereto with a maturity date of March 1, 2022 (the “SN UnSub Credit Agreement”). The initial borrowing base amount under the SN UnSub Credit Agreement was $330 million. Additionally, the SN UnSub Credit Agreement provides for the issuance of letters of credit, generally limited in the aggregate to the lesser of $50 million and the total availability under the borrowing base. Availability under the SN UnSub Credit Agreement is at all times subject to customary conditions and the then applicable borrowing base, which is subject to periodic redetermination. As of June 30, 2018, there were approximately $167.5 million of borrowings and no letters of credit outstanding under the SN UnSub Credit Agreement.

Semi-annual redeterminations of the borrowing base are generally scheduled to occur in April and October of each year. On May 11, 2018, the SN UnSub Credit Agreement was amended in conjunction with the Spring 2018 redetermination to, among other things, (i) increase the borrowing base from $330 million to $380 million, (ii) reduce the applicable margins on borrowings outstanding, (iii) reduce the proven reserves minimum collateral requirement, (iv) reduce the restrictions on SN UnSub’s ability to make certain investments, restricted payments, and debt repayments and (v) provide a more permissive maximum hedging covenant.

The next regularly scheduled borrowing base redetermination is expected in the fourth quarter of 2018. In addition, the borrowing base is subject to interim redetermination at the request of SN UnSub or the lenders based on, among other things, the lenders’ evaluation of SN UnSub’s and its subsidiaries’ oil and natural gas reserves. The borrowing base is also subject to reduction by 25% of the amount of certain junior debt issuances other than the first $200 million of such debt and by reductions as a result of hedge terminations and asset dispositions that exceed 5% of the then-effective borrowing base, in addition to other customary adjustments.

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The obligations under the SN UnSub Credit Agreement are guaranteed by all of SN UnSub's existing and future subsidiaries and secured by a first priority lien on substantially all of SN UnSub's assets and the assets of SN UnSub's existing and future subsidiaries, including a first priority lien on all ownership interests in existing and future subsidiaries as well as a pledge of equity interests in SN UnSub held by SN EF UnSub Holdings, LLC ("SN UnSub Holdings") and SN EF UnSub GP, LLC, the general partner of SN UnSub (the "SN UnSub General Partner"), in each case, subject to customary exceptions; provided, however, that the guarantee and first priority lien requirements do not extend to existing and future subsidiaries of SN UnSub designated as "unrestricted subsidiaries." As of June 30, 2018, SN UnSub had no subsidiaries.

At SN UnSub's election, borrowings under the SN UnSub Credit Agreement may be made on an ABR or a Eurodollar rate basis, plus an applicable margin. The applicable margin varies from 1.00% to 2.00% for ABR borrowings and from 2.00% to 3.00% for Eurodollar borrowings, depending on the utilization of the borrowing base. In addition, SN UnSub is also required to pay a commitment fee on the amount of any unused commitments at a rate of 0.50% per annum. Interest on ABR borrowings and the commitment fee are generally payable quarterly. Interest on the Eurodollar borrowings are generally payable at the applicable maturity date.

The SN UnSub Credit Agreement contains various affirmative and negative covenants and events of default that limit SN UnSub's ability to, among other things, incur indebtedness, make restricted payments, grant liens, consolidate or merge, dispose of certain assets, make certain investments, engage in transactions with affiliates, enter into and maintain hedge transactions and make certain acquisitions.

The SN UnSub Credit Agreement also provides for an event of default upon a change of control and cross default between the SN UnSub Credit Agreement and other indebtedness of SN UnSub in an aggregate principal amount exceeding $25 million. Additionally, the SN UnSub Credit Agreement contains "separateness" covenants that require SN UnSub to comply with certain corporate formalities and transact with affiliates on an arms' length basis and to indicate in the consolidated financial statements that SN UnSub and SN UnSub General Partner are separate entities apart from their respective security holders and affiliates and the assets and credit of SN UnSub and SN UnSub General Partner are not available to satisfy the debts and other obligations of such security holders and affiliates or any other person or entity. Furthermore, the SN UnSub Credit Agreement contains financial covenants that require SN UnSub to satisfy certain specified financial ratios, including (i) a current assets to current liabilities ratio of at least 1.0 to 1.0 as of the last day of each fiscal quarter and (ii) a net debt to consolidated EBITDAX ratio of not greater than 4.0 to 1.0 for each test period, in each case commencing with the fiscal quarter ending June 30, 2017. As of June 30, 2018, the Company was in compliance with the covenants of the SN UnSub Credit Agreement.

From time to time, the agents, arrangers, book runners and lenders under the SN UnSub Credit Agreement and their affiliates have provided, and may provide in the future, investment banking, commercial lending, hedging and financial advisory services to SN UnSub 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.

SR Credit Agreement

As of June 30, 2018, we had approximately $24.0 million in past due borrowings under an existing credit facility of an unrestricted subsidiary acquired as part of the SR Settlement (as defined in Note 12, "Related Party Transactions") (the "SR Credit Agreement"), which debt is Non-Recourse to the Company and to the obligors under the SN UnSub Credit Agreement and the Non-Recourse Subsidiary Term Loan. Although the original maturity date of the SR Credit Agreement was August 7, 2018, on April 18, 2017, prior to the Company's acquisition of Sanchez Resources, LLC ("Sanchez Resources"), the administrative agent and the lender thereunder accelerated the obligations due under the SR Credit Agreement as a result of various defaults thereunder. If we do not repay the approximately $24.0 million in borrowings due under the SR Credit Agreement or successfully renegotiate the terms of such facility, then the administrative agent or the lender under that facility could proceed against the collateral securing that debt, consisting of substantially all of Sanchez Resources' assets (approximately 14,000 net acres largely in the TMS trend). Management is currently in discussions to renegotiate this facility. See Note 12, "Related Party Transactions."

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Senior Notes

7.75% Senior Notes Due 2021

On June 13, 2013, we completed a private offering of $400 million in aggregate principal amount of the 7.75% senior notes that will mature on June 15, 2021 (the “Original 7.75% Notes”). Interest on the notes is payable on June 15 and December 15 of each year. We received net proceeds from this offering of approximately $388 million, after deducting initial purchasers’ discounts and offering expenses, which we used to repay our then outstanding indebtedness. 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 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 the 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. 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 of the 6.125% senior notes due 2023 (the “Original 6.125% Notes”). Interest on the notes is payable on July 15 and January 15 of each year. 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 previous credit facility and to finance a portion of the purchase price of our acquisition of 106,000 net contiguous acres in Dimmit, LaSalle and Webb Counties, Texas (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

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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 and the 7.25% Senior Secured 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 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. The Company may also be required to repurchase the 6.125% Notes upon a change of control or if we sell certain Company assets.

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

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, Registrar and Paying Agent ("Trustee") under the indentures of the 6.125% Notes and the 7.75% 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.

7.25% Senior Secured First Lien Notes due 2023

On February 14, 2018, the Company closed its private offering to eligible purchasers of $500 million in aggregate principal amount of 7.25% senior secured first lien notes due 2023 (the "7.25% Senior Secured Notes"). The 7.25% Senior Secured Notes were issued pursuant to an indenture, dated as of February 14, 2018 (the "Indenture"), among the Company, the guarantors party thereto, Delaware Trust Company, as trustee, and Royal Bank of Canada, as collateral trustee.

The 7.25% Senior Secured Notes are guaranteed on a full, joint and several and senior secured basis by each of the Company's existing domestic restricted subsidiaries and will be guaranteed by any future domestic restricted

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subsidiary, in each case, if and so long as such entity guarantees (or is an obligor with respect to) indebtedness (other than the 7.25% Senior Secured Notes) in excess of $10 million or under the Credit Agreement. The 7.25% Senior Secured Notes are secured by first-priority liens on substantially all of the Company's and any subsidiary guarantor's assets. The 7.25% Senior Secured Notes and the guarantees are, pursuant to a collateral trust agreement (the "CTA"), secured by first-priority liens on a "second-out" collateral proceeds payment priority basis and thus are effectively junior to any "first-out" obligations, including obligations under the Credit Agreement and obligations under any hedging arrangements and cash management arrangements permitted to be secured on a "first-out" basis under the Credit Agreement, to the extent of the value of the collateral securing such "first-out" obligations. The 7.25% Senior Secured Notes and the guarantees rank effectively senior to all of the Company's existing and future senior unsecured indebtedness to the extent of the value of the collateral securing the 7.25% Senior Secured Notes and the guarantees.

The 7.25% Senior Secured Notes will mature on February 15, 2023, unless on October 10, 2022 either (i) some or all of the Company's 6.125% Notes are still outstanding and have not been defeased or (ii) the Company or any of its restricted subsidiaries have any outstanding indebtedness that was used to purchase, repurchase, redeem, defease or otherwise acquire or retire for value the Company's 6.125% Notes, and such indebtedness under this clause (ii) has a final maturity date that is earlier than May 17, 2023, in which case of either clause (i) or clause (ii), the 7.25% Senior Secured Notes will mature on October 14, 2022.

The 7.25% Senior Secured Notes are redeemable, in whole or in part, on or after February 15, 2020 at the redemption prices described in the Indenture, together with accrued and unpaid interest. At any time prior to February 15, 2020, the Company may redeem the 7.25% Senior Secured 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 to the redemption date. In addition, the Company may redeem up to 35% of the 7.25% Senior Secured Notes prior to February 15, 2020 in an amount not greater than the net cash proceeds from one or more equity offerings at a redemption price equal to 107.25% of their principal amount, together with accrued and unpaid interest to the redemption date. If the Company sells certain of its assets or experiences specific kinds of changes of control, in certain circumstances it must offer to repurchase the 7.25% Senior Secured Notes.

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

The 7.25% Senior Secured Notes and the guarantees are secured on a first-priority basis, subject in priority only to permitted collateral liens and to the prior rights of the Credit Agreement and other "first-out" obligations under the CTA, in the following assets of the Company and the subsidiary guarantors (the "Shared Collateral"): (i) substantially all of the Company's and its restricted subsidiaries' oil and natural gas properties with proved reserves, (ii) 100% of the equity interest of the Company's restricted subsidiaries and any of their future direct material restricted subsidiaries; and (iii) substantially all of the Company's and any guarantor's other material personal property, but in each case excluding, among other things, deposit accounts, oil and natural gas properties with no proved reserves, equity interests in SN UnSub and other existing and future subsidiaries designated as “unrestricted subsidiaries.”

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Note 8. Derivative Instruments

To reduce the impact of fluctuations in the price of oil, natural gas and NGLs 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 or extend the notional quantity settlement period 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 Credit Agreement, the SN UnSub Credit Agreement and the terms of SN UnSub's organizational documents, as applicable, 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 participants. Any derivatives that are with (x) lenders, or affiliates of lenders, to the SN UnSub Credit Agreement, or (y) counterparties designated as secured with and under the Credit Agreement are, in each case, collateralized by the assets securing the applicable facility and, therefore, do not currently require the posting of cash collateral. Any derivatives that are with (x) non-lender counterparties, as designated under the SN UnSub Credit Agreement, or (y) counterparties that are not designated as secured under the Credit Agreement are, in each case, unsecured and do not require the posting of cash or other 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 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.

The following table presents derivative positions for the periods indicated as of June 30, 2018:

	July 1 - December 31, 2018	2019	2020
Oil positions:			
Fixed-for-floating price swaps (NYMEX WTI):			
Hedged volume (Bbls)	4,039,794	3,149,000	599,400
Average price ($/Bbl)	$ 52.27	$ 51.91	$ 54.31
Call swaptions (NYMEX WTI):			
Option volume (Bbls)	—	730,000	—
Average price ($/Bbl)	$ —	$ 55.00	$ —
Natural gas positions:			
Fixed-for-floating price swaps (NYMEX Henry Hub):			
Hedged volume (MMbtu)	34,957,648	17,644,000	3,862,500
Average price ($/MMbtu)	$ 3.01	$ 2.90	$ 2.74

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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, 2018 and the year ended December 31, 2017 (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Beginning fair value of commodity derivatives	$ (54,255)	$ (35,014)
Net losses on crude oil derivatives	(108,018)	(48,966)
Net gains (losses) on natural gas derivatives	(6,099)	42,764
Net settlements paid (received) on commodity derivative contracts:		
Crude oil	51,996	(11,807)
Natural gas	(5,907)	(1,232)
Ending fair value of commodity derivatives	$ (122,283)	$ (54,255)

Embedded Derivatives: In 2017, the Company entered into contracts for the purchase of sand and fractionation stimulation services that contain provisions that are required to be bifurcated from the contract and valued as derivatives. The embedded derivatives are valued using a Monte Carlo simulation model which utilizes observable inputs, including the NYMEX WTI oil price and NYMEX Henry Hub natural gas price at various points in time. The Company has marked these derivatives to market as of June 30, 2018 and 2017. The Company incurred an approximate $6.1 million loss and a $0.2 million gain as a result for the six months ended June 30, 2018 and 2017, respectively. Any gains or losses related to embedded derivatives are recorded as a component of other income (expense) in the condensed consolidated statement of operations.

Earnout Derivative: As part of the Carnero Gathering Disposition (defined in Note 12, "Related Party Transactions"), we are entitled to receive earnout payments from SNMP based on natural gas delivered above a threshold volume and tariff at the delivery points of the Carnero Gathering pipeline, a pipeline owned by Carnero G&P (as defined in Note 12. "Related Party Transactions.") These payments were deemed to be a derivative; the resulting earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. As a result, the Company incurred approximate gains of $1.3 million and $1.5 million for the three and six months ended June 30, 2018. Any gains or losses related to the earnout derivative are recorded as a component of other income (expense) in the condensed consolidated statement of operations.

The following table sets forth a reconciliation of the changes in fair value of the Company's embedded and earnout derivatives (in thousands):

	Six Months Ended	Year Ended

	June 30, 2018	December 31, 2017
Beginning fair value of other derivatives	$ (1,551)	$ —
Loss on embedded derivatives	(6,053)	(1,551)
Initial fair value of earnout derivative	6,401	—
Gain on earnout derivative	1,527	—
Ending fair value of other derivatives	$ 324	$ (1,551)

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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, 2018		
	Gross Amount of Recognized Assets and Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts Presented in the Consolidated Balance Sheets
Offsetting Derivative Assets:			
Current asset	$ 3,791	$ (550)	$ 3,241
Long-term asset	9,148	(312)	8,836
Total asset	$ 12,939	$ (862)	$ 12,077
Offsetting Derivative Liabilities:			
Current liability	$ 103,454	$ (550)	$ 102,904
Long-term liability	31,444	(312)	31,132
Total liability	$ 134,898	$ (862)	$ 134,036

	December 31, 2017		
	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	$ 16,510	$ (80)	$ 16,430
Long-term asset	2,100	(672)	1,428
Total asset	$ 18,610	$ (752)	$ 17,858
Offsetting Derivative Liabilities:			
Current liability	$ 56,270	$ (80)	$ 56,190
Long-term liability	18,146	(672)	17,474
Total liability	$ 74,416	$ (752)	$ 73,664

Note 9. Investments

On June 15, 2017, the Company received 1,500,000 shares of Lonestar's Series B Convertible Preferred Stock as part of the consideration for the Marquis Disposition. The Series B Convertible Preferred Stock converted into Lonestar Class A Common Stock on November 3, 2017. As of June 30, 2018, this ownership represents approximately 6.1% of Lonestar's outstanding shares of common stock. The investment in Lonestar is accounted for by the Company as investments in equity securities measured at fair value in the condensed consolidated balance sheets at the end of each reporting period. The Company recorded a gain related to the investment in Lonestar for the three and six months ended June 30, 2018 of approximately $6.7 million and $6.2 million, respectively. Any gains or losses related to the investment in Lonestar are recorded as a component of other income (expense) in the condensed consolidated statement of operations.

On June 14, 2017, SN Catarina, LLC ("SN Catarina"), a wholly owned subsidiary of the Company, completed the sale of its 10% undivided interest in the Silver Oak II Gas Processing Facility in Bee County, Texas (the "SOII Facility") to a subsidiary of Targa Resources Corp. ("Targa") with an effective date of June 1, 2017 for $12.5 million of cash (the "SOII Disposition"). Prior to the SOII Disposition, the Company recorded earnings of approximately $677 thousand from its equity interest in the SOII Facility for the six months ended June 30, 2017.

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On March 1, 2017 (the "Effective Date"), pursuant to the Amended and Restated Limited Liability Company Agreement (the "LLC Agreement") of Gavilan Resources Holdco, LLC ("GRHL" or "Gavilan Holdco"), GRHL authorized and issued a total of 100 Class A Units to SN Comanche Manager, LLC, a wholly owned unrestricted subsidiary of the Company ("SN Comanche Manager" or "Manager"). GRHL is the parent of Gavilan. SN Comanche Manager, as holder of the Class A Units, does not have voting rights with respect to GRHL except regarding amendments to the LLC Agreement that adversely affect the holders of Class A Units, approval of affiliate transactions, or as required by law. Twenty percent of the Class A Units vest on each of the first five anniversaries of the Effective Date. The Class A Units are entitled to distributions from Available Cash, as defined in and subject to the provisions of the LLC Agreement. The Company accounts for the investment in GRHL as a cost method investment. As of June 30, 2018, the carrying value of the investment in GRHL was $7.3 million, based on the estimated fair value as of March 1, 2017. In general, the fair value of a cost method investment is not evaluated unless circumstances are present that may have an adverse effect on the fair value. The Company has not identified any such circumstances as of June 30, 2018. The Company did not record any earnings from its ownership of the Class A Units for the three or six months ended June 30, 2018.

On November 22, 2016, a subsidiary of the Company purchased 2,272,727 of SNMP's common units for $25.0 million in a private placement. As of June 30, 2018, this ownership represents approximately 14.20% of SNMP's outstanding common units. Rather than accounting for the investment under the equity method, the Company elected the fair value option to account for its interest in SNMP. The Company records the equity investment in SNMP at fair value at the end of each reporting period. The Company recorded gains related to the investment in SNMP for the three and six months ended June 30, 2018 of approximately $3.3 million and $1.6 million, respectively. In addition, for the three and six months ended June 30, 2018, the Company recorded dividend income of approximately $1.0 million and $2.0 million, respectively, from quarterly dividends on the investment in SNMP. Any gains or losses and dividend income related to the investment in SNMP are recorded as a component of other income (expense) in the condensed consolidated statement of operations.

Note 10. 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. Substantially all of these inputs are observable in the marketplace throughout the term of the 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).

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, 2018 and December 31, 2017 (in thousands):

	As of June 30, 2018			
	Level 1	Level 2	Level 3	Total
Cash and cash equivalents:				
Cash equivalents	$ 357,643	$ —	$ —	$ 357,643
Equity investment:				
Investment in SNMP	26,818	—	—	26,818
Investment in Lonestar	12,660	—	—	12,660
Oil derivative instruments:				
Swaps	—	(117,479)	—	(117,479)
Call swaptions	—	(8,178)	—	(8,178)
Gas derivative instruments:				
Swaps	—	3,375	—	3,375
Other:				
Embedded derivative instruments	—	(7,604)	—	(7,604)
Earnout derivative asset	—	—	7,928	7,928
Total	$ 397,121	$ (129,886)	$ 7,928	$ 275,163

	As of December 31, 2017			
	Level 1	Level 2	Level 3	Total
Cash and cash equivalents:				
Cash equivalents	$ 49,071	$ —	$ —	$ 49,071
Equity investment:				
Investment in SNMP	25,227	—	—	25,227
Investment in Lonestar	5,955	—	—	5,955
Oil derivative instruments:				
Swaps	—	(66,204)	—	(66,204)
Call swaptions	—	(3,431)	—	(3,431)
Gas derivative instruments:				
Swaps	—	15,380	—	15,380
Other:				
Embedded derivative instruments	—	(1,551)	—	(1,551)
Total	$ 80,253	$ (55,806)	$ —	$ 24,447

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, 2018 and December 31, 2017. 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. In addition, the Level 1 instruments include the Company's equity investment in common units of SNMP as further discussed in Note 9, "Investments." The investment in SNMP is being accounted for under the fair value option and included in investments on the Company's condensed consolidated balance sheet as of June 30, 2018 and December 31, 2017. The Company identified the common units in SNMP as a Level 1 instruments due to the fact that SNMP is a publicly traded company on the NYSE American with daily quoted prices that can be readily obtained. The Level 1 instruments also include the Company's investment in the common shares of Lonestar as further discussed in Note 9, "Investments." The investment in the Lonestar common shares is being accounted for at fair value and included in investments on the Company's condensed consolidated balance sheet as of June 30, 2018 and December 31, 2017. The Company identified the Lonestar common shares as Level 1 instruments due to the fact that Lonestar is a publicly traded company on the Nasdaq Global Market exchange, with daily quoted prices that can be readily obtained.

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The Company’s commodity derivative instruments consist of swaps and call swaptions as of June 30, 2018 and December 31, 2017 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 generally have observable inputs and they are classified as Level 2. Call swaption derivatives have inputs which are observable, either directly or indirectly, using market data. As of June 30, 2018 and December 31, 2017, the Company believed that substantially all of the inputs required to calculate the fair value of swaps and call 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. Derivative instruments are also subject to the risk that counterparties will be unable to meet their obligations. Such non-performance risk is considered in the valuation of the Company’s derivative instruments, but to date has not had a material impact on estimates of fair values. Significant changes in the quoted forward prices for commodities and changes in market volatility generally lead to corresponding changes in the fair value measurement of the Company’s derivative instruments.

There were no commodity derivative instruments classified as Level 3 as of June 30, 2018 or December 31, 2017.

Embedded Derivatives: The Company consummated contracts for the purchase of sand and fractionation stimulation services that contain provisions that are required to be bifurcated from the contract and valued as a derivative. The embedded derivatives are using a Monte Carlo simulation model which utilizes observable inputs, including the NYMEX WTI oil price and the NYMEX Henry Hub natural gas price at various points in time. As of June 30, 2018 and December 31, 2017, the Company believes that substantially all of the inputs required to calculate the embedded derivatives 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 inputs. Changes in the inputs will impact the fair value measurement of the Company's embedded derivative contracts.

Earnout Derivative: As part of the Carnero Gathering Disposition, we are entitled to receive earnout payments from SNMP based on natural gas delivered above a threshold volume and tariff at Carnero Gathering pipeline’s delivery points. These payments were deemed to be a derivative; the resulting earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. We have therefore classified the fair value measurements of the earnout derivative as Level 3.

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

	June 30, 2018

Beginning balance	$ —
Initial fair value of earnout derivative	6,401
Gain on earnout derivative	1,527
Ending balance	$ 7,928

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 Comanche Acquisition is presented in Note 4, "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 11, "Asset Retirement Obligations."

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As previously stated, the Company follows the provisions of ASC 820 10 for nonfinancial assets and liabilities measured at fair value on a non recurring basis. The fair value measurements of assets acquired and liabilities assumed in the SR legal settlement 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. The allocation of fair value to the assets and liabilities assumed as part of the SR legal settlement is presented in Note 12, “Related Party Transactions.” Liabilities assumed include asset retirement obligations existing and short-term debt held by Sanchez Resources at the date of transfer. 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. Additional discussion of the SR legal settlement can be found in Note 12, “Related Party Transactions.” A reconciliation of the beginning and ending balances of the Company’s asset retirement obligations is presented in Note 11, “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 Preferred Stock and Series B Preferred Stock, the Company issued common stock according to the conversion rate pursuant to each agreement and additional shares to induce the holders of the preferred stock to convert prior to the date the Company could mandate conversion. In addition, on November 20, 2015, a holder of our Series B Preferred Stock exercised its right to convert 4,500 shares of 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. There were no conversions of Series A Preferred Stock or Series B Preferred Stock into shares of the Company’s common stock during the six months ended June 30, 2018 and year ended December 31, 2017. 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 14, “Stockholders’ and Mezzanine Equity.”

The Company did not record a proved property impairment during the six months ended June 30, 2018 and year ended December 31, 2017.

Fair Value of Other Financial Instruments

The carrying amounts of our oil and natural gas receivables, accounts payable and accrued liabilities approximate fair value due to their highly liquid nature. The registered 7.75% Notes and 6.125% Notes are traded in an active market, and as such, are classified as Level 1 financial instruments. The estimated fair value of the 7.75% Notes and 6.125% Notes was $514.0 million and $788.9 million as of June 30, 2018, respectively, and was calculated using quoted market prices based on trades of such debt as of that date. The 7.25% Senior Secured Notes are classified as Level 1 financial instruments as they are traded in an active market under Rule 144A by institutional investors. The estimated fair value of the 7.25% Senior Secured Notes was $495.0 million as of June 30, 2018 and was calculated using quoted market prices based on trades of such debt as of that date.

Note 11. Asset Retirement Obligations

The Company’s 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. 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, changes in property lives, and the expected timing of settlement.

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The changes in the asset retirement obligation for the six months ended June 30, 2018 and the year ended December 31, 2017 were as follows (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Abandonment liability, beginning of period	$ 36,098	$ 25,087
Liabilities incurred during period	1,018	4,968
Acquisitions	—	8,289
Divestitures	(158)	(3,538)
Revisions	—	(1,343)
Accretion expense	1,541	2,635
Abandonment liability, end of period	$ 38,499	$ 36,098

Note 12. 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, including the Company, pursuant to existing management service agreements. The Company refers to SOG and its affiliates (but excluding the Company) collectively as the "Sanchez Group." Mr. Eduardo A. Sanchez and Ana Lee Sanchez Jacobs, immediate family members of the Executive Chairman of the Board, our Chief Executive Officer and an Executive Vice President of the Company, collectively with such individuals, either directly or indirectly, own 100% of the equity interests of SOG; these individuals, as well as Mr. Eduardo A. Sanchez and Ms. Ana Lee Sanchez Jacobs, are officers of SOG. In addition, Antonio R. Sanchez, Jr. is the sole member of the board of directors of SOG.

The Company does not have any employees. On December 19, 2011, the Company entered into the 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 are allocated to the Company based on a detailed analysis of actual time spent by the professional staff on Company projects and activities. The allocation is reviewed at least annually and is adjusted as necessary. General and administrative expenses such as office rent, utilities, supplies and other overhead costs, are allocated on the same basis as the SOG employee salaries. Expenses allocated to the Company for general and administrative expenses and oil and natural gas production expenses for the three months ended June 30, 2018 and 2017, were $15.6 million and $18.7 million, respectively, and expenses allocated to the Company for general and administrative expenses and oil and natural gas production expenses for the six months ended June 30, 2018 and 2017 were $33.5 million and $34.2 million, respectively.

As of June 30, 2018 and December 31, 2017, the Company had a net receivable from SOG and other members of the Sanchez Group of $6.2 million and $4.5 million, respectively, which are reflected as "Accounts receivable—related entities" in the condensed consolidated balance sheets. The net receivable as of June 30, 2018 and December 31, 2017 consists primarily of advances paid related to general and administrative and other costs paid to SOG.

As of June 30, 2018 and December 31, 2017, the Company had a net payable to SNMP of approximately $4.7 million and $9.8 million, respectively, that consists primarily of the accrual for fees associated with the gathering agreement signed with SNMP as part of the Company's sale of SN Catarina's interests in Catarina Midstream, LLC, a wholly-owned subsidiary of SN Catarina (the "Western Catarina Midstream Divestiture"), which is reflected in the "Accrued Liabilities - Other" account on the condensed consolidated balance sheets. On June 30, 2017, the gathering agreement was amended to, among other things, provide for an additional, incremental infrastructure fee (the "Incremental Infrastructure Fee") payable to SNMP of $1.00 per barrel of water delivered by SNMP on or after April 1, 2017 through and including March 31, 2018 and to eliminate certain late payment fees from SN Catarina to SNMP. The parties have agreed to continue the Incremental Infrastructure Fee on a month-to-month basis. On September 1, 2017, SN Catarina entered into an agreement with Seco Pipeline, LLC, ("Seco Pipeline") a wholly owned subsidiary of SNMP, whereby Seco Pipeline transports certain quantities of natural gas on a firm basis for $0.22 per MMbtu delivered on or after September 1, 2017. This agreement had an initial term of one month that expired on September 30, 2017, but the agreement has continued month-to-month and will continue to do so until terminated by either party.

In May 2018, SNMP executed a series of agreements with an affiliate of Targa pursuant to which the parties merged their respective 50% interests in Carnero Gathering LLC ("Carnero Gathering") and Carnero Processing LLC ("Carnero Processing") to form an expanded 50/50 joint venture in South Texas, Carnero G&P LLC ("Carnero G&P"). In addition to the merger, Targa contributed 100% of the equity interests in the SOII Facility to Carnero G&P, expanding the processing capacity of the joint venture ("Carnero G&P Transaction"). Effective April 1, 2018, SN Maverick and Carnero G&P entered into a Firm Gas Gathering, Processing and Purchase Agreement (the "Carnero Gas Gathering Agreement") and other related documentation providing for certain gas gathering, treating and processing services in exchange for an approximately 315,000 gross acreage dedication from SN Maverick and its working interest partners. Additionally, effective April 1, 2018, and in connection with the Carnero G&P Transaction, SN Catarina and an affiliate of Targa also amended their Firm Gas Gathering Agreement (the "Amended Gathering Agreement") and Firm Gas Processing Agreement (the "Amended Processing Agreement"), which were subsequently assigned by the Targa counterparty to Carnero G&P.

Antonio R. Sanchez, III, the son of Antonio R. Sanchez, Jr. and brother of Patricio D. Sanchez, is the Company's Chief Executive Officer and is a member of the board of directors of both the Company and of the general partner of SNMP ("SNMP GP"). Patricio D. Sanchez, an Executive Vice President of the Company, is the President and Chief Operating Officer of SNMP GP and a director of SNMP GP. Eduardo A. Sanchez, the brother of Antonio R. Sanchez, III and Patricio D. Sanchez and the son of Antonio R. Sanchez, Jr., is a director of SNMP GP. Antonio R. Sanchez, Jr., the Executive Chairman of the Board of the Company, Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez all directly or indirectly own certain equity interests in the Company, SNMP and SNMP GP. Antonio R. Sanchez, Jr., Antonio R. Sanchez, III, Eduardo A. Sanchez and Patricio D. Sanchez beneficially own approximately 0.72%, 2.47%, 2.42% and 3.52%, respectively, of the SNMP common units outstanding as of June 30, 2018 and, together with Ana Lee Sanchez Jacobs, indirectly own 100% of SNMP GP.

SNMP Unit Acquisition

On November 22, 2016, a subsidiary of the Company purchased 2,272,727 common units of SNMP for $25.0 million in a private placement (see Note 9, “Investments”).

SNMP Lease Option

On October 6, 2016, the Company and SN Terminal, LLC (“SNT”), a wholly owned subsidiary of the Company, on the one hand, and SNMP, on the other hand, entered into a Purchase and Sale Agreement (the “Lease Option Purchase Agreement”) pursuant to which SNT sold and conveyed to SNMP an option to acquire a ground lease (the “Lease Option”) to which SNT was a party for a tract of land leased from the Calhoun Port Authority in Point Comfort, Texas. In addition, if the Company or any of its affiliates entered into an option to engage in the construction of or participation in a Project (as defined below) and/or received the benefit of an acreage dedication from an affiliate of the Company relating to a Project, then such option and/or acreage dedication would have also been assigned to SNMP, if SNMP exercised the Lease Option. SNMP would have paid SNT $1.00 if the Lease Option was exercised, along with $250,000 if SNMP or any other person affiliated with SNMP elected to construct, own or operate a marine crude storage terminal on or within five miles of the Port Comfort lease or participated as an investor in the same, within five miles thereof (a “Project”), or the Company or its affiliates conveyed an acreage dedication to or an option regarding a Project. On September 11, 2017, the Company, SNT and SNMP entered into an agreement that terminated the Lease Option.

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Carnero Processing Disposition

On November 22, 2016, SN Midstream sold its membership interests in Carnero Processing to SNMP for an initial payment of $55.5 million and the assumption by SNMP of remaining capital commitments to Carnero Processing, which were estimated at approximately $24.5 million (the “Carnero Processing Disposition”). Carnero Processing is no longer in existence, as its assets have been contributed to Carnero G&P through the Carnero G&P Transaction; however, as part of the disposition, the Company recorded a deferred gain of approximately $7.5 million included in “Other Liabilities” on the condensed consolidated balance sheet as a result of the Amended Processing Agreement that remains in effect between the Company and Carnero G&P. This deferred gain was to be amortized over the term of the Amended Processing Agreement according to volumes processed through the Carnero Processing facility; however, upon adoption of ASC 606, this deferred gain was reversed and opening retained earnings was adjusted as of January 1, 2018. Refer to Note 18, “Revenue Recognition” for additional discussion.

Carnero Gathering Disposition

On July 5, 2016, SN Midstream sold its membership interests in Carnero Gathering to SNMP for an initial payment of approximately $37.0 million and the assumption by SNMP of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million (the “Carnero Gathering Disposition”). In connection with the Carnero G&P Transaction, Carnero Processing merged into Carnero Gathering and Carnero Gathering was renamed Carnero G&P. However, as part of the original disposition of Carnero Gathering, the Company recorded a deferred gain of approximately $8.7 million included in “Other Liabilities” on the condensed consolidated balance sheet as a result of the Amended Gathering Agreement that remains in effect between the Company and Carnero G&P. This deferred gain was to be amortized periodically over the term of the Amended Gathering Agreement according to volumes processed through the Carnero Processing facility; however, upon adoption of ASC 606, this deferred gain was reversed and opening retained earnings was adjusted as of January 1, 2018. The Company recognized an earnout derivative asset related to the Carnero Gathering Disposition in the amount of $6.4 million upon adoption of ASC 606 which is revalued at each reporting period. Refer to Note 8, “Derivative Instruments” for additional discussion of the earnout derivative asset and Note 18, “Revenue Recognition” for additional discussion of the impact of ASC 606.

Comanche Acquisition

On March 1, 2017, we closed the Comanche Acquisition and, in connection with the closing, entered into a number of transactions with Gavilan, GSO Capital Partners L.P. (“GSO”) and the Blackstone Warrantholders (as defined below), or their affiliates, which are related parties (see Note 4, “Acquisitions and Divestitures”), including (i) the SPA (defined below) with an investment vehicle owned by certain funds managed or advised by GSO (“the GSO Funds”) and a controlled affiliate of GSO, (ii) warrant agreements with the Blackstone Warrantholders, (iii) Registration Rights Agreements (as defined below) with the Blackstone Warrantholders and the GSO Funds, (iv) the Partnership

Agreement (as defined below) with an entity controlled by an affiliate of GSO, and (v) the GP LLC Agreement (as defined below) with a controlled affiliate of GSO (see Note 14, "Stockholders' and Mezzanine Equity").

In addition, in connection with the closing of the Comanche Acquisition, we also entered into (i) separate standstill and voting agreements (the "Standstill Agreements") with the Blackstone Funds (as defined below) and the GSO Funds, respectively, (ii) an eight-year (subject to earlier termination as provided for therein) joint development agreement (the "JDA") with Gavilan, (iii) a shareholders agreement (the "Shareholders Agreement") with Gavilan Holdco, (iv) a management services agreement (the "Management Services Agreement") with Gavilan Holdco and SN Comanche Manager, and (v) certain marketing agreements with Gavilan.

Each Standstill Agreement (i) restricts the ability of each of Blackstone Capital Partners VII L.P. and Blackstone Energy Partners II L.P. (together, the "Blackstone Funds") and the GSO Funds (and indirectly certain of their affiliates) to take certain actions relating to the acquisition of our securities or assets or participation in our management, (ii) contains a two year lock-up restricting dispositions of the Company's common stock or the warrants to purchase the Company's common stock, and (iii) contains an agreement to vote any voting securities of the Company in the same manner as recommended by our Board.

Pursuant to the Shareholders Agreement, Gavilan Holdco has the right, but not the obligation, to appoint one observer representative to be present at all regularly scheduled meetings of the full board of directors of the Company.

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The JDA provides for the administration, operation and transfer of the jointly owned Comanche Assets, and further provides for the (i) establishment of an operating committee to control the timing, scope and budgeting of operations on the Comanche Assets (subject to certain exceptions) and (ii) designation of SN Maverick as operator of the Comanche Assets and certain other interests (subject to forfeiture in the event of certain default events); the JDA also provides for mechanics relating to division of assets and operatorship among the parties, contains restrictions on the indirect or direct transfer of the parties' interests in the Comanche Assets, including certain tag-along rights and rights of first offer provisions, and provides Gavilan with certain drag-along rights in the event of certain sale transactions, subject to certain exceptions and potential alternative structures or asset divisions.

Pursuant to the Management Services Agreement, the Manager serves as manager of Gavilan Holdco's business and provides comprehensive general, administrative, business and financial services at a price equal to Manager's actual cost of providing such services (including an "administrative fee" equal to 2% of SOG's total G&A costs), continuing until the occurrence of one or more events giving Manager or Gavilan Holdco the right to terminate the agreement. At the closing of the Comanche Acquisition, Gavilan Holdco paid $1.0 million to Manager under the agreement. The Management Services Agreement provides that Manager may not bill more than $500,000 of G&A costs per month to Gavilan Holdco (subject to reasonable adjustments that are consistent with market terms as a result of an increase in actual G&A costs incurred, and based upon a reasonable allocation of such costs). We also entered into a back-to-back management arrangement between Manager and SOG, on substantially the same terms and conditions as the Management Services Agreement, pursuant to which Manager delegated to SOG, and SOG agreed to perform for and on behalf of Manager, Manager's duties and obligations under such services agreement; Manager is required to remit amounts received directly from Gavilan Holdco to Manager, including the $1.0 million paid at closing to Manager, and to pay SOG the 2% administrative fee referred to above. In addition, we entered into a management services agreement between SOG and SN UnSub pursuant to which SOG serves as manager of SN UnSub's oil and natural gas properties and provides comprehensive general, administrative, business and financial services at a price equal to SOG's actual cost of providing such services (including an "administrative fee" equal to 2% of SOG's total G&A costs), with an initial term expiring on March 1, 2024 (subject to earlier termination as provided therein), renewing automatically for additional one-year terms thereafter unless either SN UnSub or SOG delivers written notice to the other of its desire not to renew the term at least 180 days prior to such anniversary date. SOG may not bill G&A costs to SN UnSub in excess of $5 million per calendar year until March 1, 2019, or in excess of $10 million per calendar year thereafter.

Pursuant to a crude oil production marketing agreement, a residue gas marketing agreement and a marketing agreement for NGLs between Gavilan and SN Maverick, Gavilan sells all of its production from the Comanche Assets to SN Maverick and SN Maverick purchases all such production from Gavilan, transports and sells such production and remits to Gavilan its proportionate share of the sale proceeds

Pursuant to the LLC Agreement of GRHL, GRHL authorized and issued a total of 100 Class A Units to SN Comanche Manager. SN Comanche Manager, as holder of the Class A Units, does not have voting rights with respect to GRHL except regarding amendments to the LLC Agreement that adversely affect the holders of Class A Units, approval of affiliate transactions, or as required by law. Twenty percent of the Class A Units vest on each of the first five anniversaries of the effective date of March 1, 2017. The holders of Class A Units are entitled to distributions from

Available Cash, as defined in and subject to the provisions of the LLC Agreement. As of June 30, 2018, no distributions of Available Cash had been made to the Company.

SR Settlement

On August 11, 2017, the Company, the plaintiffs and all named defendants In re Sanchez Energy Derivative Litigation, Consolidated C.A. No. 9132-VCG in the Court of Chancery of the State of Delaware (the “Court”), relating to the Company’s August 2013 purchase of working interests in the TMS from Sanchez Resources, entered into a Stipulation of Settlement (the “Stipulation”) reflecting the terms of the settlement of the derivative stockholder litigation (the “SR Settlement”). On November 6, 2017, the Stipulation was approved by the Court and became final on December 20, 2017 with an effective date of November 29, 2017, pursuant to which, among other things: (i) the defendants (or their insurance companies) made a payment to the Company of an aggregate of $11.75 million ($5.2 million, net of fees, expenses and other amounts); (ii) the sole member of Sanchez Resources transferred the equity of Sanchez Resources to us; (iii) Sanchez Resources transferred certain royalty interests in the TMS acreage held by Sanchez Resources to us, and (iv) Alan Jackson and Greg Colvin were removed from the Company’s compensation committee. Sanchez Resources and one of its subsidiaries is party to the SR Credit Agreement of which approximately

$24.0 million is outstanding. See Note 7, “Debt” for additional discussion of the SR Credit Agreement. The credit facility is solely secured by substantially all of the assets of Sanchez Resources and/or its subsidiary, without recourse to SN or any of its other subsidiaries, consisting of approximately 14,000 net acres largely in the TMS trend. The assets and liabilities underlying the equity interests transferred to the Company were recorded following the provisions of ASC 820 to measure nonfinancial assets and liabilities at fair value. The fair value measurements were based on market and cost approaches utilizing third-party market participant operating and development estimates. The assets and liabilities underlying the equity interests transferred to the Company were recorded at fair value on a preliminary basis as of the date of the transfer as follows (in thousands):

Proved oil and natural gas properties	$ 15,867
Unproved properties	7,482
Other assets acquired	2,739
Fair value of assets acquired	26,088
Asset retirement obligations	(2,092)
Fair value of net assets acquired	$ 23,996

Note 13. Accrued Liabilities and Other Current Liabilities

The following information summarizes accrued liabilities on the condensed consolidated balance sheet as of June 30, 2018 and December 31, 2017 (in thousands):

	June 30, 2018	December 31, 2017
Capital expenditures	$ 93,506	$ 85,340
Other:		
General and administrative costs	8,440	8,855
Production taxes	5,444	5,084
Ad valorem taxes	7,721	84
Lease operating expenses	26,520	32,152
Interest payable	47,911	34,632
Other accrued liabilities	—	3,987
Total accrued liabilities	$ 189,542	$ 170,134

The following information summarizes other payables on the condensed consolidated balance sheet as of June 30, 2018 and December 31, 2017 (in thousands):

	June 30, 2018	December 31, 2017
Revenue payable	$ 83,705	$ 72,451
Production tax payable	3,881	2,774
Other	12,865	6,745
Total other payables	$ 100,451	$ 81,970

The following information summarizes other current liabilities on the condensed consolidated balance sheet as of June 30, 2018 and December 31, 2017 (in thousands):

	June 30, 2018	December 31, 2017
Operated prepayment liability	$ 41,636	$ 88,999
Deferred gain on Western Catarina Midstream Divestiture - short term	23,720	23,720
Phantom compensation payable - short term	5,751	2,525
Total other current liabilities	$ 71,107	$ 115,244

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Note 14. Stockholders’ and Mezzanine Equity

Common Stock Offerings

On May 25, 2017, the Company entered into an equity distribution agreement with Citigroup Global Markets, Inc., BMO Capital Markets Corp., Capital One Securities, Inc., RBC Capital Markets, LLC and SunTrust Robinson Humphrey, Inc. and filed with the SEC a prospectus supplement to our shelf registration statement that allows us to issue from time to time shares of our common stock up to an aggregate gross amount of $75 million (the “2017 ATM”). Sales of our common stock, if any, under the 2017 ATM will be made by any method permitted by law deemed to be an “at the market” offering as defined under the Securities Act, including, without limitation, sales made directly on the New York Stock Exchange, on any other existing trading market for our shares of common stock or to or through a market maker or as otherwise agreed by the Company and the sales agent. As of June 30, 2018, we had not issued any shares of our common stock under the 2017 ATM.

On February 6, 2017, the Company completed an underwritten public offering of 10,000,000 shares of the Company's common stock at a price to the public of $12.50 per share ($11.7902 per share, net of underwriting discounts). The Company granted the underwriters a 30-day option to purchase up to an additional 1,500,000 shares of the Company’s common stock on the same terms, which was exercised in full and closed on February 6, 2017. The Company received net proceeds of approximately $135.9 million (after deducting underwriting discounts of approximately $7.8 million) from the sale of the shares of common stock.

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, 2018, 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, 2018, all dividends accumulated through that date had been paid. The dividends accrued for the period from April 1 to June 30, 2018, were declared by the Board and paid in cash to the Company’s paying agent on June 29, 2018 and distributed by the agent to holders on July 2, 2018.

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

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

If a holder elects to convert shares of Series A Preferred Stock upon the occurrence of certain specified fundamental changes, the Company will be obligated to deliver an additional number of shares above the applicable

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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, 2018, 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, 2018, all dividends accumulated through that date had been paid. The dividends accrued for the period from April 1 to June 30, 2018, were declared by the Board and paid in cash to the Company’s paying agent on June 29, 2018 and distributed by the agent to holders on July 2, 2018.

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.

NOL Rights Plan

On July 28, 2015, the Company entered into a net operating loss carryforwards rights plan (as amended, the "Rights Plan") with Continental Stock Transfer & Trust Company, as rights agent. In connection therewith, the Board declared a dividend of one preferred share purchase right ("Right") for each outstanding share of the Company's common stock. The dividend was paid on August 10, 2015 to stockholders of record as of the close of business on August 7, 2015 (the "NOL Record Date"). In addition, one Right automatically attaches to each share of common stock issued between the NOL Record Date and such date as when the Rights become exercisable. On March 1, 2017, the Company amended the Rights Plan to, among other things, amend certain defined terms to account for the issuance of warrants and grant of shares of common stock to the GSO Funds and the issuance of warrants to the Blackstone Warrantholders in connection with the closing of the Comanche Acquisition.

Common Stock and Stock Warrants Issuance

At the closing of the Comanche Acquisition pursuant to the Amended and Restated Securities Purchase Agreement (the "SPA"), and subject to the other terms and conditions provided therein: (i) the GSO Funds received 1,455,000 shares of the Company's common stock and warrants to purchase 1,940,000 shares of the Company's common stock at an exercise price of $10 per share, subject to customary anti-dilution adjustments; and (ii) Intrepid

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Private Equity V-A LLC ("Intrepid") received 45,000 shares of the Company's common stock and warrants to purchase 60,000 shares of the Company's common stock at an exercise price of $10 per share, subject to customary anti-dilution adjustments. The warrants issued to the GSO Funds and Intrepid expire on March 1, 2032, in each case in accordance with the terms and conditions of the applicable warrant agreement.

Also at the closing of the Comanche Acquisition, the Company entered into (i) three separate warrant agreements to purchase an aggregate of 6,500,000 shares of the Company's common stock with each of Gavilan Resources Holdings—A, LLC, Gavilan Resources Holdings —B, LLC, and Gavilan Resources Holdings—C, LLC (collectively, the "Blackstone Warrantholders"), that provide for a $10 exercise price per share to purchase the Company's common stock, subject to customary anti-dilution adjustments. The warrants issued to the Blackstone Warrantholders expire on March 1, 2022 in accordance with the terms and conditions of the applicable warrant agreement.

The exercise price and the number of shares of the Company's common stock for which a warrant is exercisable are subject to adjustment from time to time upon the occurrence of certain events including: (i) payment of a dividend or distribution to holders of shares of the Company's common stock payable in the Company's common stock, (ii) a subdivision, combination, or reclassification of the Company's common stock, (iii) the distribution of any rights, options or warrants (excluding rights issued under the Rights Plan) to all holders of the Company's common stock entitling them for a certain period of time to purchase shares of the Company's common stock at a price per share less than the fair market value per share, and (iv) payment of a cash distribution to all holders of the Company's common stock or a distribution to all holders of the Company's common stock any shares of the Company's capital stock, evidences of indebtedness, or any of assets or any rights, warrants or other securities of the Company. The warrant agreements also provide that, if the Company proposes a voluntary or involuntary dissolution, liquidation or winding up of the affairs of the Company, the holders of the warrants will receive the kind and number of other securities or assets which the holder would have been entitled to receive if the holder had exercised the warrant in full immediately prior to the time of such dissolution, liquidation or winding up and the right to exercise the warrant will terminate on the date on which the holders of record of the shares of common stock are entitled to exchange their shares for securities or assets deliverable upon such dissolution, liquidation or winding up.

In addition, the Company entered into separate registration rights agreements with the Blackstone Warrantholders, the GSO Funds, and Intrepid (collectively, the "Registration Rights Agreements"). The Registration Rights Agreements grant the parties certain registration rights for the shares of our common stock acquired by the parties, including the shares issuable upon the exercise of the warrants to purchase the Company's common stock. The Registration Rights Agreements with the Blackstone Warrantholders and the GSO Funds provide that the Company will use its reasonable best efforts to prepare and file a shelf registration statement with the SEC to permit the public resale of all registrable securities covered by the applicable Registration Rights Agreement within 18 months of the date of the agreement and to cause such shelf registration statement to be declared effective no later than two years after the date of the agreement.

The Registration Rights Agreements include piggyback rights for the applicable holders, which provide that, if the Company proposes to file certain registration statements or supplements to certain effective registration statements for the sale of shares of the Company's common stock in an underwritten offering for its own account or that of another person or both, then the Company is required to offer the holders the opportunity to include in such underwritten offering such number of registrable securities as each such holder may request, subject to certain cutback rights if the Company has been advised by the managing underwriter that the inclusion of registrable securities for sale for the benefit of the holders will have an adverse effect on the price, timing or distribution of the shares of common stock in the underwritten offering.

SN Comanche Manager, LLC Class A Preferred Unit Member

On the Effective Date, pursuant to the LLC Agreement, Gavilan Holdco authorized and issued a total of 100 Class A Units to SN Comanche Manager. GRHL is the parent of Gavilan. SN Comanche Manager, as holder of the Class A Units, does not have voting rights under the LLC Agreement except with respect to amendments to the LLC Agreement that adversely affect the holders of Class A Units, approval of affiliate transactions, or as required by law. Twenty percent of the Class A Units vest on each of the first five anniversaries of the Effective Date. The holders of Class A Units are entitled to distributions from Available Cash (as defined in the LLC Agreement) subject to the provisions of the LLC Agreement.

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SN UnSub Preferred Unit Issuance

At the closing of the Comanche Acquisition, pursuant to the SPA and subject to the other terms and conditions provided therein, the GSO Funds purchased 485,000 preferred units of SN UnSub for $485,000,000 and Intrepid purchased 15,000 preferred units of SN UnSub for $15,000,000 (in aggregate, the "SN UnSub Preferred Units"). The applicable parties entered into an amended and restated partnership agreement of SN UnSub (the "Partnership Agreement") and an amended and restated limited liability company agreement of SN UnSub General Partner (the "GP LLC Agreement").

Under the terms of the Partnership Agreement, holders of the SN UnSub Preferred Units are entitled to receive distributions of 10.0% per annum, payable quarterly in cash, unless a cash payment is then prohibited by certain of SN UnSub's debt agreements, in which case such distribution will be deemed to have been paid in kind. SN UnSub may not make distributions on the SN UnSub common units until the preferred units are redeemed in full.

The SN UnSub Preferred Units have priority over the common units, to the extent of the Base Return (as defined below), upon a liquidation, sale of all or substantially all assets, certain change of control and exit transactions.

SN UnSub may, from time to time and subject to the conditions set forth in the Partnership Agreement and the SN UnSub Credit Agreement, redeem SN UnSub Preferred Units at a purchase price per unit sufficient to achieve the greater of (i) the amount required to cause the return on investment with respect to each such SN UnSub Preferred Unit to be equal to the product of (x) 1.5 multiplied by (y) the purchase price per unit and (ii) the amount required to cause the internal rate of return with respect to each SN UnSub Preferred Unit to be equal to 14.0%, in each case inclusive of previous distributions made in cash (the "Base Return"). Partners holding a majority of the SN UnSub Preferred Units will have the option to request SN UnSub to redeem all of the preferred units for the Base Return at any time following the seventh anniversary of issuance or upon the occurrence of certain change of control transactions, as further described in the Partnership Agreement.

If (i) the SN UnSub Preferred Units are not timely redeemed by SN UnSub when required, (ii) SN UnSub fails, after March 1, 2018, to pay the holders of the SN UnSub Preferred Units a cash distribution in any two quarters, regardless of whether consecutive, and such failure is continuing, (iii) SN UnSub takes certain material actions without the consent of the holders of the SN UnSub Preferred Units, when required, (iv) certain events of default under SN UnSub and the Company's credit agreements have occurred or (v) SN Maverick is removed as operator under the JDA under certain circumstances, then a controlled affiliate of GSO will be entitled to appoint a majority of the members of the board of directors of SN UnSub General Partner and may cause a sale of the assets or equity of SN UnSub in order to redeem the SN UnSub Preferred Units.

The SN UnSub Preferred Units issued in March 2017 are accounted for as mezzanine equity in the condensed consolidated balance sheet consisting of the following as of June 30, 2018 and December 31, 2017, respectively, (in thousands):

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Mezzanine equity beginning balance	$ 427,512	$ —
Private placement of SN UnSub Preferred Units	—	500,000
Discount	—	(90,527)
Accretion of Discount	12,119	18,039
Dividends accrued (1)	25,000	41,667
Dividends prepaid (2)	(2,592)	—
Dividends/distributions paid (3)	(9,908)	(41,667)
Total mezzanine equity	$ 452,131	$ 427,512

(1) In accordance with the Partnership Agreement and SN UnSub Credit Agreement, cash distributions for the 10% dividend on the SN UnSub Preferred Units were prohibited through February 28, 2018, and thus, the dividends for the year ended December 31, 2017 were deemed to have been accrued and offset by the tax distributions paid. The dividends for the first and second quarters of 2018 were accrued and paid in cash on March 30, 2018 and July 2, 2018, respectively.

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(2) In 2017, tax distributions of approximately $2.6 million were paid in excess of the accrued dividend. The excess distribution was offset against a portion of the dividend accrued and paid during the three months ended March 31, 2018.

(3) Distributions paid in 2017 represent tax distributions from available cash to holders of the SN UnSub Preferred Units. The Partnership Agreement provides that tax distributions shall be treated as advances of and shall be offset against any amounts holders of the SN UnSub Preferred Units are entitled to receive.

Earnings (Loss) Per Share—The following table shows the computation of basic and diluted net income (loss) per share for the three and six months ended June 30, 2018 and 2017 (in thousands, except per share amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss)	$ (34,987)	$ 52,988	$ (39,804)	$ 68,723
Less:				
Preferred stock dividends	(3,987)	(3,987)	(7,974)	(7,974)
Preferred unit dividends and distributions	(12,500)	(10,950)	(22,408)	(27,415)
Preferred unit amortization	(6,189)	(5,282)	(12,119)	(6,992)
Net income (loss) allocable to participating securities(1)(2)	—	(2,378)	—	(1,974)
Net income (loss) attributable to common stockholders	$ (57,663)	$ 30,391	$ (82,305)	$ 24,368
Weighted average number of unrestricted outstanding common shares used to calculate basic net income (loss) per share	81,787	76,395	81,356	73,045
Dilutive shares(3)(4)(5)	—	12,620	—	100
Denominator for diluted earnings (loss) per common share	81,787	89,015	81,356	73,145
Net income (loss) per common share - basic	$ (0.71)	$ 0.40	$ (1.01)	$ 0.33
Net income (loss) per common share - diluted	$ (0.71)	$ 0.39	$ (1.01)	$ 0.33

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

(2) For the three and six months ended June 30, 2018, 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 months ended June 30, 2017 excludes 942,841 shares of weighted average restricted stock from the calculation of the denominator for diluted loss per common share as these shares were anti-dilutive.

(4) The six months ended June 30, 2017 excludes 1,304,160 shares of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted loss per common share as these shares were anti-dilutive.

(5) The three and six months ended June 30, 2018 excludes 2,484,202 and 756,417 shares, respectively, of weighted average restricted stock and 12,520,179 shares of common stock resulting from an assumed conversion of the Company's Series A Preferred Stock and Series B Preferred Stock from the calculation of the denominator for diluted loss per common share as these shares were anti-dilutive.

Note 15. 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 Board had previously approved the LTIP on April 20, 2016, subject to stockholder approval.

The Company’s directors and consultants as well as employees of the Sanchez Group who provide services to the Company are eligible to participate in the LTIP. Awards to participants may be made in the form of 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, that 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 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 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. Forfeitures of restricted stock awards granted to non-employees are accounted for as they are incurred.

During the three and six months ended June 30, 2018, the Company issued approximately 2.7 million and 3.2 million 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, respectively. 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 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"). No PARS or PAPS were granted during the six months ended June 30, 2018.

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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 on the PARS 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 using the straight-line method.

During the three and six months ended June 30, 2018, the Company issued approximately 4.6 million and 5.8 million shares of Phantom Stock pursuant to the LTIP to certain employees of SOG (including the Company's officers), with whom the Company has a services agreement, respectively. These shares of Phantom Stock vest in equal annual amounts over a three-year period.

On March 1, 2017, the Company's Chief Executive Officer, Executive Chairman of the Board, President, and Chief Operating Officer entered into a new form of agreement for use in equity awards pursuant to the LTIP, for 245,234 target shares of the Company's common stock, 245,234 target shares of the Company's common stock, 245,234 target shares of the Company's common stock, and 81,745 target shares of the Company's common stock, respectively. The new form of agreement is a performance phantom stock agreement payable in shares of common stock (the "Performance Phantom Stock Agreement"). The shares granted pursuant to the Performance Phantom Stock Agreement (the "Performance Awards") will vest (if any) in equal annual increments over a five-year period ranging from 0% to 200% of the target phantom shares granted based on the Company's share price appreciation relative to the share price appreciation of the S&P Oil & Gas Exploration & Production Select Industry Index for each year in the five-year performance period beginning on January 1, 2017 and ending on December 31, 2021, subject to each officer's continuous service with the Company through each vesting date. For the 2017 performance period applicable to these awards, 0% of the target shares were awarded.

The performance awards 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 Performance Awards are classified as equity within the Company's balance sheet, as they are settled in shares of the Company's common stock. The Performance Awards have graded-vesting features and as such, the compensation expense for the unvested awards is calculated using the graded-vesting method whereby the Company recognizes compensation expense over the requisite service period for each separately vesting tranche of the award as though they were, in substance, multiple awards. In addition, the estimated value of each tranche will be revalued at each period end and amortized over the vesting period.

On April 17, 2018, the Company and certain of its key executives entered into new equity award agreements pursuant to the LTIP, whereby the key executives were granted the following performance-based phantom stock awards:

	Cash-Settled	Stock-Settled
	Target Performance-Based Phantom Shares	
Chief Executive Officer	506,230	506,230
Executive Chairman of the Board	506,230	506,230
Executive Vice President and Chief Financial Officer	186,916	186,916
Executive Vice President	253,115	253,115
Senior Vice President and Chief Operating Officer	186,916	186,916

The awards were issued pursuant to (i) cash-settled performance phantom stock agreements payable only in cash (the "Cash-Settled Performance-Based Phantom Stock Agreement" or "Cash-Settled PBPS Awards") and (ii) stock-settled performance phantom stock agreements payable in shares of common stock (the "Stock-Settled Performance-Based Phantom Stock Agreement" or "Stock-Settled PBPS Awards" and together with the Cash-Settled PBPS Awards, the "PBPS Awards"). Vesting of the shares granted pursuant to the PBPS awards will occur over a three-year performance period beginning January 1, 2018 and ending December 31, 2020, subject to each officer's continuous

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service with the Company through each vesting date. Such shares will vest (if at all) in equal annual increments ranging from 0% to 200% of the target phantom shares based on four performance criteria: (1) leverage metrics (net debt to EBITDAX ratio); (2) reserves replacement (reserve replacement ratio); (3) LOE/Boe (production expense divided by production); and (4) safety (as measured based on the total recordable incident rate ("TRIR")). Each performance measure for a calendar year within the performance period is weighted 30% (or 10% in the case of TRIR) to determine the number of phantom shares earned (if any) during that calendar year. The overall results of each performance measure during a calendar year within a performance period are weighted by approximately 33% to determine the number of phantom shares earned (if any) during the entire performance period.

The applicable vesting date for each calendar year within the performance period will be 60 days following the end of such calendar year. Vested awards will be settled (i) in the case of Stock-Settled PBPS Awards, by the delivery of one share of Common Stock for each Stock-Settled PBPS Award that vests on the applicable vesting date in a calendar year, and (ii) in the case of Cash-Settled PBPS Awards, by the payment in cash of an amount equal to the fair market value of the Common Stock on the vesting date times the number of Cash-Settled PBPS Awards that vests on the applicable vesting date in a calendar year. Settlement will occur as soon as reasonably practicable following the applicable vesting date, but in all events, no later than the end of the year in which the applicable vesting date occurs.

The PBPS Awards 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 Cash-Settled PBPS Awards are classified as liabilities within the Company's balance sheet, as they are required to be settled cash, while the Stock-Settled PBPS Awards are classified as equity within the Company's condensed consolidated balance sheet, as they are settled in shares of the Company's common stock. The PBPS Awards have graded-vesting features and as such, the compensation expense for the unvested awards is calculated using the graded-vesting method whereby the Company recognizes compensation expense over the requisite service period for each separately vesting tranche of the award as though they were, in substance, multiple awards. In addition, the estimated value of each tranche will be revalued at each period end and amortized over the vesting period.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Restricted stock awards, directors	$ 330	$ 619	$ 627	$ 4,601
Restricted stock awards, non-employees	3,023	2,982	2,819	10,548
Performance awards	1,298	734	830	1,277
Phantom stock awards	5,017	3,024	4,119	13,965
Total stock-based compensation expense	$ 9,668	$ 7,359	$ 8,395	$ 30,391

Based on the $4.52 per share closing price of the Company's common stock on June 30, 2018, there was approximately $20.9 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 $4.52 per share closing price of the Company's common stock on June 30, 2018, there was approximately $0.5 million of unrecognized compensation cost related to the non vested PARS outstanding. The cost is expected to be recognized over an average period of approximately 2.80 years.

Based on the $4.52 per share closing price of the Company's common stock on June 30, 2018, there was approximately $20.3 million of unrecognized compensation cost related to the non vested PAPS and Phantom Stock outstanding. The cost is expected to be recognized over an average period of approximately 1.95 years.

Based on the estimated per share price of the Performance Awards on June 30, 2018, there was approximately $1.0 million of unrecognized compensation cost related to the Performance Awards. The cost is estimated to be recognized over a weighted average period of approximately 2.9 years.

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Based on estimated per share price of the common stock underlying the PBPS Awards on June 30, 2018, there was approximately $7.4 million of unrecognized compensation cost related to the PBPS Awards. The cost is estimated to be recognized over a weighted average period of approximately 1.85 years.

A summary of the activity of the non-vested restricted shares and PARS for the three and six months ended June 30, 2018 and 2017 is presented below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Non-vested common stock, beginning of period	3,684	6,336	4,897	6,891
Granted	2,676	282	3,156	2,076
Vested	(542)	(711)	(2,159)	(3,060)
Forfeited	(51)	(47)	(127)	(47)
Non-vested common stock, end of period	5,767	5,860	5,767	5,860

As of June 30, 2018, approximately 5.8 million shares remain available for future issuance to participants under the LTIP assuming achievement of the maximum payment under all outstanding Performance Awards and Stock-Settled PBPS Awards.

A summary of the activity of the non vested Phantom Stock shares and PAPS for the three and six months ended June 30, 2018 and 2017 is presented below (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Non-vested phantom stock and PAPS, beginning of period	3,949	4,690	3,589	4,012
Granted	2,474	191	3,652	1,986
Vested	(435)	(663)	(1,150)	(1,780)
Forfeited	(100)	(20)	(203)	(20)
Non-vested phantom stock and PAPS, end of period	5,888	4,198	5,888	4,198

Note 16. Income Taxes

The Company used a year-to-date effective tax rate method for recording income taxes for the six month periods ended June 30, 2018 and 2017. This method is based on our expectations at June 30, 2018 and 2017 that a small change in our estimated ordinary income could result in a large change in the estimated annual effective tax rate. We will use this method each quarter until such time a return to the annualized effective tax rate method is deemed appropriate.

The Company's effective tax rate for the six months ended June 30, 2018 and 2017 was 0.0% and (1.8%,) respectively. The difference between the statutory federal income taxes calculated using a U.S. Federal statutory corporate income tax rate of 21% and the Company's effective tax rate of 0.0% for the six months ended June 30, 2018 is related to the valuation allowance on deferred tax assets. The Company's effective tax rate of (1.8%) for the six months ended June 30, 2017 is primarily related to the recording of certain deferred tax liabilities associated with the Comanche Acquisition that were recorded directly to equity, whereas the correlating movement in the valuation allowance was required to be recorded to income tax expense.

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

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and, therefore, has established a valuation allowance to reduce the deferred tax assets as of June 30, 2018. 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, 2018, the Company had no material uncertain tax positions.

On December 22, 2017, the President signed into law Public Law No. 115-97, a comprehensive tax reform bill

commonly referred to as the Tax Cuts and Jobs Act (the “Tax Act”) that significantly reforms the Internal Revenue Code of 1986, as amended (the “Code”). Among the many provisions included in the Tax Act is a provision to reduce the U.S. federal corporate income tax rate from 35% to 21% effective January 1, 2018.

We recognized the income tax effects of the Tax Act in accordance with Staff Accounting Bulletin No. 118, which provides SEC staff guidance for the application of ASC 740, “Income Taxes.” The guidance allows for a measurement period of up to one year after the enactment date to finalize the recording of the related tax impacts. As such, our financial results reflect the provisional income tax effects of the Tax Act for which the accounting under ASC 740 is incomplete, but a reasonable estimate could be determined. We did not identify any items for which the income tax effects of the Tax Act could not be reasonably estimated as of June 30, 2018.

We continue to assess the impact of the Tax Act on our business. Our provisional amounts may be adjusted due to changes in interpretations of the Tax Act, legislative action to address questions that arise because of the Tax Act, or changes in accounting standards for income taxes or related interpretations. Any updates or changes to provisional estimates will be reported in the reporting period in which any such adjustments are determined, which will be no later than the fourth quarter of 2018.

Note 17. 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.

Catarina Drilling Obligation

In connection with the Catarina Acquisition, the undeveloped acreage we acquired is 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 drilling period on a well-for-well basis. The lease also creates 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.

Comanche Drilling Obligation

In connection with the Comanche Acquisition, we, through our subsidiaries, SN Maverick and SN UnSub, and Gavilan, entered into a development agreement with Anadarko. The development agreement requires us to complete and equip 60 wells in each annual period commencing on September 1, 2017 and continuing thereafter until September 1, 2022. The development agreement permits up to 30 wells completed and equipped in excess of the annual 60 well requirement to be carried over to satisfy part of the 60 well requirement in subsequent annual periods on a well-for-well basis. The development agreement contains a parent guarantee of the performance of SN Maverick and SN UnSub. If we fail to complete and equip the required number of wells in a given year (after applying any qualifying additional wells from previous years), we and Gavilan must pay Anadarko E&P Onshore, LLC a default fee of $0.2 million for each well we do not timely complete and equip. 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.

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Lease Payment Obligations

As of June 30, 2018, the Company had $158.9 million in lease payment obligations that satisfy operating lease criteria. These obligations include: (i) $75.9 million in payments due with respect to firm commitment of oil and natural gas volumes under the gathering agreement contract signed with SNMP as part of the Western Catarina Midstream Divestiture that commenced on October 14, 2015 and continues until October 13, 2020, (ii) $78.5 million for corporate and field office leases with expiration dates through March 2025, and (iii) $4.5 million for a 10 year acreage lease agreement for a promotional ranch managed by the Company in Kenedy County, Texas.

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 nine months advanced written notice and payment of any accrued leasehold expenses.

Volume Commitments

As is common in our industry, the Company is party to certain oil and natural gas gathering and transportation and natural gas processing agreements that obligate us to deliver a specified volume of production over a defined time horizon. If not fulfilled, the Company is subject to deficiency payments. As of June 30, 2018, the Company had approximately $2,021.9 million in future commitments related to oil and natural gas gathering and transportation agreements ($664.0 million for 2018 through 2020, $673.5 million from 2021 through 2023, and $684.4 million under commitments expiring after December 31, 2023, in the aggregate) and approximately $571.2 million in future commitments related to natural gas processing agreements ($198.4 million for 2018 through 2020, $113.5 million from 2021 through 2023, and $259.30 million expiring after December 31, 2023, in the aggregate) that are not recorded in the accompanying condensed consolidated balance sheets.

For the three and six months ended June 30, 2018, the Company incurred expenses related to deficiency fees of approximately $1.7 million and $2.3 million, respectively, and for the three and six months ended June 30, 2017, the Company incurred expenses related to deficiency fees of approximately $1.4 million and $1.4 million, respectively. These expenses are reported on the condensed consolidated statements of operations in the "Oil and natural gas production expenses" line item. We expect to have additional expenses in 2018 related to our volume commitments.

Amended Gathering Agreement and Amended Processing Agreement

As of June 30, 2018, the Company had $58.4 million and $57.7 million in payments with respect to firm commitment of natural gas volumes associated with the Carnero Gathering Pipeline and either the Raptor Processing Plant or SOII Facility, respectively, all owned by Carnero G&P and due under the Amended Gathering Agreement and Amended Processing Agreement. These agreements commenced on October 2, 2015 and continue until October 2, 2030.

Note 18. Revenue Recognition

Adoption of ASC 606

Effective January 1, 2018, we adopted the new accounting standard ASC 606, “Revenue from Contracts with Customers,” and all the related amendments (collectively referred to as “ASC 606”) to all open contracts using the modified retrospective method. We recognized the cumulative effect of initially applying the new revenue standard as an adjustment to the opening balance of retained earnings. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods.

For contracts that were modified before the beginning of the earliest reporting period presented, we elected to use a practical expedient permitted under the rules of adoption whereby contracts do not need to be retrospectively restated for contract modifications. Instead, we have reflected the aggregate effect of all modifications that occur before the beginning of the earliest period presented.

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Adoption of this guidance resulted in the derecognition of $16.3 million in deferred gains recorded under the Carnero Gathering Disposition and Carnero Processing Disposition and the recognition of a $6.4 million derivative asset in the value of the earnout provision owed to us by SNMP with a $22.7 million decrease to accumulated deficit as of January 1, 2018. The earnout derivative asset was marked to market and incurred approximate gains of $1.3 million and $1.5 million, respectively, during the three and six months ended June 30, 2018 as a result.

The cumulative effect of the changes made to our consolidated January 1, 2018 condensed consolidated balance sheet for the adoption of ASC 606 were as follows (in thousands):

Balance Sheet	As of December 31, 2017	Adjustments Due to ASC 606	As of January 1, 2018
Assets			
Fair value of derivative instruments	$ 16,430	$ 150	$ 16,580
Total current assets	350,798	150	350,948
Fair value of derivative instruments	1,428	6,251	7,679
Total assets	$ 2,470,635	$ 6,401	$ 2,477,036
Liabilities			
Other liabilities	$ 65,480	$ (16,338)	$ 49,142
Total liabilities	2,512,263	(16,338)	2,495,925
Equity			
Accumulated deficit	(1,832,156)	22,739	(1,809,417)
Total stockholders' deficit	(469,140)	22,739	(446,401)
Total liabilities and stockholders' deficit	$ 2,470,635	$ 6,401	$ 2,477,036

Revenue from Contracts with Customers

Beginning in 2018, we account for revenue from contracts with customers in accordance with ASC 606. The unit of account in ASC 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. ASC 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

ASC 606 provides additional clarification related to principal versus agent considerations. We enter into marketing agreements with our non-operating partners to market and sell their share of production to third parties. We have determined that we act as an agent in such arrangements and account for such arrangements on a net basis.

Certain of our contracts for the sale of commodities meet the definition of a derivative. We have elected the normal purchases and normal sales scope exception as provided by ASC 815, Derivatives and Hedging, and account for such contracts in accordance with ASC 606.

Disaggregation of Revenue

We recognized revenue of $259.3 million and $510.5 million for the three and six months ended June 30, 2018, respectively. We disaggregate revenue in our income statement based on product type, and we further disaggregate our revenue related to sales and marketing revenue.

In selecting the disaggregation categories, we considered a number of factors, including disclosures presented outside the financial statements, such as in our earnings release and investor presentations, information reviewed internally for evaluating performance, and other factors used by the Company or the users of its financial statements to evaluate performance or allocate resources. As such, we have concluded that disaggregating revenue by product type appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

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Oil, Natural Gas, and NGL Revenues

We recognize revenue from the sale of oil, natural gas and NGLs in the period that the performance obligations are satisfied. Our performance obligations are primarily comprised of the delivery of oil, gas, or NGLs at a delivery point. Each barrel of oil, MMbtu of natural gas, or other unit of measure is separately identifiable and represents a distinct performance obligation to which the transaction price is allocated. Performance obligations are satisfied at a point in time once control of the product has been transferred to the customer through monthly delivery of oil, natural gas and NGLs.

We sell oil at market based prices with adjustments for location and quality. Under our oil sales contracts, we transfer control of the product to the purchaser at the delivery point and recognize revenue based on the contract price.

Under our natural gas sales contracts, we deliver natural gas to the purchaser at an agreed upon delivery point. Natural gas is transported from our wellheads to delivery points specified under sales contracts. To deliver natural gas to these points, third parties gather, process and transport our natural gas. We maintain control of the natural gas during gathering, processing, and transportation. We transfer control of the product at the delivery point and recognize revenue based on the contract price. The costs to gather, process and transport the natural gas are recorded as Oil and natural gas production expenses.

NGLs, which are extracted from natural gas through processing, are either sold by us directly or by the processor under processing contracts. For NGLs sold by us directly, we transfer control of the product to the purchaser at the delivery point and recognize revenue based on the contract price. The costs to further process and transport NGLs are recorded as Oil and natural gas production expenses. For NGLs sold by the processor, our processing contracts provide that we transfer control to the processor at the tailgate of the processing plant and we recognize revenue based on the price received from the processor.

Our contracts with customers typically require payment for oil and condensate, gas and NGL sales within 30 days following the calendar month of delivery. The sales of oil and condensate, gas and NGLs typically include variable consideration that is based on pricing tied to local indices adjusted for differentials and volumes delivered in the current month. Revenues include estimates for the two most recent months using published commodity price indexes and volumes supplied by field operators.

Sales and Marketing Revenue

Beginning in the first quarter of 2018, we entered into commodity purchase transactions with third parties and then subsequently sold the purchased commodity as separate revenue streams. These purchase contracts were entered into to utilize existing firm transportation arrangements. We retain control of the purchased hydrocarbons prior to delivery to the purchaser. The Company has concluded that we are the principal in these arrangements and therefore we recognize revenue on a gross basis as Sales and Marketing Revenues within our condensed consolidated statement of operations, with costs to purchase and transport the commodity presented as Sales and Marketing Expenses in our condensed consolidated statement of operations. Contracts to sell the third-party hydrocarbons are the same contracts as those for which we sell our produced hydrocarbons, and as such, we do not recognize this revenue any differently than our oil, natural gas, and NGL revenue discussed previously.

Remaining Performance Obligations

Several of our sales contracts contain multiple performance obligations as each barrel of oil, MMbtu of natural gas, or other unit of measure is separately identifiable. For these contracts, we have taken the optional exception under ASC 606-10-50-14A(b) which is available only for wholly unsatisfied performance obligations for which the criteria in ASC 606-10-32-40 have been met. Under this exception, neither estimation of variable consideration nor disclosure of the transaction price allocated to the remaining performance obligations is required. Revenue is alternatively recognized in the period that the control of the commodity is transferred to the customer and the respective variable component of the total transaction price is resolved.

For forms of variable consideration that are not associated with a specific volume and thus do not meet the allocation exception, estimation is required. Examples of such variable consideration consist of deficiency payments, late payment fees, truck rejection charges, inflation adjustments, and imbalance penalties, however, these items are

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immaterial to our consolidated financial statements and/or have a low probability of occurrence. As significant reversals of revenue due to this variability are not probable, no estimation is required.

Contract Balances

Under our sales contracts, we invoice customers after our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At June 30, 2018 and December 31, 2017, our receivables from contracts with customers were $88.2 million and $101.4 million, respectively.

Reconciliation of Condensed Consolidated Balance Sheet

In accordance with the new revenue standard requirements, the disclosure of the impact of adoption on our condensed consolidated balance sheet is as follows (in thousands):

	As of June 30, 2018		
Balance Sheet	Balances without Adoption ASC 606	Effect of change higher/(lower)	As Reported
Assets			
Fair value of derivative instruments	$ 2,979	$ 262	$ 3,241
Total current assets	561,737	262	561,999
Fair value of derivative instruments	1,170	7,666	8,836
Total assets	$ 2,896,486	$ 7,928	$ 2,904,414
Liabilities			
Other liabilities	$ 50,670	$ (16,338)	$ 34,332
Total liabilities	2,988,496	(16,338)	2,972,158
Equity			
Accumulated deficit	(1,915,986)	24,266	(1,891,720)
Total stockholders' deficit	(544,141)	24,266	(519,875)
Total liabilities and stockholders' deficit	$ 2,896,486	$ 7,928	$ 2,904,414

Reconciliation of Condensed Consolidated Statement of Operations

In accordance with the new revenue standard requirements, the disclosure of the impact of adoption on our condensed consolidated statement of operations for the three and six months ended June 30, 2018 is as follows (in thousands):

	Three Months Ended June 30, 2018		
	Balances without Adoption ASC 606	Effect of change higher/(lower)	As Reported
Statement of Operations			
Other income (expense)	$ 5,461	$ 1,254	$ 6,715
Total other income (expense)	(106,117)	1,254	(104,863)
Income (loss) before income taxes	(36,241)	1,254	(34,987)
Net income (loss)	$ (36,241)	$ 1,254	$ (34,987)

	Six Months Ended June 30, 2018		
	Balances without Adoption ASC 606	Effect of change higher/(lower)	As Reported
Statement of Operations			
Other income (expense)	$ 8,616	$ 1,527	$ 10,143
Total other income (expense)	(190,194)	1,527	(188,667)
Income (loss) before income taxes	(41,331)	1,527	(39,804)
Net income (loss)	$ (41,331)	$ 1,527	$ (39,804)

We expect the impact of the adoption of the new standard to be immaterial to our net income on an ongoing basis.

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Note 19. Condensed Consolidating Financial Information

The Company's 7.75% Notes and 6.125% Notes have been registered with the SEC and are guaranteed by all of the Company's subsidiaries, except for SN UR Holdings, LLC, SN Services, LLC, SNT, SN Midstream, Manager, SN UnSub General Partner, SN UnSub Holdings, SN UnSub, SN Capital, LLC, Sanchez Resources, SR Acquisition III, LLC and SR TMS, LLC which are unrestricted subsidiaries of the Company. As of June 30, 2018 such guarantor subsidiaries are 100% owned by the Company and the guarantees by these subsidiaries are full and unconditional (except for customary release provisions) and are joint and several.

Rule 3-10 of Regulation S-X requires that, in lieu of providing separate financial statements for subsidiary guarantors, condensed consolidating financial information be provided where the subsidiaries have guaranteed the debt of a registered security, where the guarantees are full, unconditional and joint and several and where the voting interest of the subsidiaries are 100% owned by the registrant.

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

The following is a presentation of condensed consolidating financial information on a parent company, combined guarantor subsidiaries, combined non-guarantor subsidiaries and consolidated basis (in thousands) in accordance with Rule 3-10 of Regulation S-X 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.

A summary of the condensed consolidated guarantor balance sheets as of June 30, 2018 and December 31, 2017 is presented below (in thousands):

	June 30, 2018		
Assets		Eliminations	Consolidated

	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries		
Total current assets	$ 633,669	$ 112,281	$ 125,872	$ (309,823)	$ 561,999
Total oil and natural gas properties, net	121,408	1,345,142	767,398	—	2,233,948
Investment in subsidiaries	1,247,762	—	(7,279)	(1,240,483)	—
Other assets	11,824	9,825	86,818	—	108,467
Total Assets	$ 2,014,663	$ 1,467,248	$ 972,809	$ (1,550,306)	$ 2,904,414
Liabilities and Shareholders' Equity					
Current liabilities	$ 199,403	$ 348,978	$ 264,888	$ (309,823)	$ 503,446
Long-term liabilities	2,214,683	58,526	195,503	—	2,468,712
Mezzanine equity	—	—	452,131	—	452,131
Total shareholders' equity (deficit)	(399,423)	1,059,744	60,287	(1,240,483)	(519,875)
Total Liabilities and Shareholders' Equity (deficit)	$ 2,014,663	$ 1,467,248	$ 972,809	$ (1,550,306)	$ 2,904,414

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	December 31, 2017				
Assets	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total current assets	$ 447,984	$ 98,758	$ 117,031	$ (312,975)	$ 350,798
Total oil and natural gas properties, net	3,987	1,275,153	748,319	—	2,027,459
Investment in subsidiaries	1,081,692	—	(7,280)	(1,074,412)	—
Other assets	25,451	4,415	62,512	—	92,378
Total Assets	$ 1,559,114	$ 1,378,326	$ 920,582	$ (1,387,387)	$ 2,470,635
Liabilities and Shareholders' Equity					
Current liabilities	$ 212,026	$ 312,531	$ 250,946	$ (312,975)	$ 462,528
Long-term liabilities	1,827,072	26,787	195,876	—	2,049,735
Mezzanine equity	—	—	427,512	—	427,512
Total shareholders' equity (deficit)	(479,984)	1,039,008	46,248	(1,074,412)	(469,140)
Total Liabilities and Shareholders' Equity (deficit)	$ 1,559,114	$ 1,378,326	$ 920,582	$ (1,387,387)	$ 2,470,635

A summary of the condensed consolidated guarantor statements of operations for the three and six months ended June 30, 2018 and 2017 is presented below (in thousands):

	Three Months Ended June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 178,842	$ 80,472	$ —	$ 259,314
Total operating costs and expenses	(24,721)	(125,167)	(39,684)	134	(189,438)
Other income	(81,192)	(5,766)	(17,771)	(134)	(104,863)
Income (loss) before income taxes	(105,913)	47,909	23,017	—	(34,987)
Income tax benefit	—	—	—	—	—
Equity in income (loss) of subsidiaries	70,926	—	—	(70,926)	—
Net income (loss)	$ (34,987)	$ 47,909	$ 23,017	$ (70,926)	$ (34,987)

	Three Months Ended June 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 111,302	$ 64,402	$ —	$ 175,704
Total operating costs and expenses	(22,154)	(70,345)	(53,921)	—	(146,420)

Other income	7,856	5,278	10,315	—	23,449
Income (loss) before income taxes	(14,298)	46,235	20,796	—	52,733
Income tax benefit	18	237	—	—	255
Equity in income (loss) of subsidiaries	67,268	—	—	(67,268)	—
Net income (loss)	$ 52,988	$ 46,472	$ 20,796	$ (67,268)	$ 52,988

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	Six Months Ended June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 346,328	$ 164,212	$ —	$ 510,540
Total operating costs and expenses	(40,252)	(207,833)	(113,862)	270	(361,677)
Other income (expense)	(147,959)	(5,263)	(35,175)	(270)	(188,667)
Income (loss) before income taxes	(188,211)	133,232	15,175	—	(39,804)
Income tax benefit (expense)	—	—	—	—	—
Equity in income (loss) of subsidiaries	148,407	—	—	(148,407)	—
Net income (loss)	$ (39,804)	$ 133,232	$ 15,175	$ (148,407)	$ (39,804)

	Six Months Ended June 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Total revenues	$ —	$ 223,130	$ 86,416	$ —	$ 309,546
Total operating costs and expenses	(86,727)	(124,950)	(75,832)	501	(287,008)
Other income (expense)	(3,378)	10,393	38,463	(501)	44,977
Income (loss) before income taxes	(90,105)	108,573	49,047	—	67,515
Income tax benefit (expense)	1,208	—	—	—	1,208
Equity in income (loss) of subsidiaries	157,620	—	—	(157,620)	—
Net income (loss)	$ 68,723	$ 108,573	$ 49,047	$ (157,620)	$ 68,723

A summary of the condensed consolidated guarantor statements of cash flows for the six months ended June 30, 2018 and 2017 is presented below (in thousands):

	Six Months Ended June 30, 2018				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (107,425)	$ 206,878	$ 55,841	$ —	$ 155,294
Net cash provided by (used in) investing activities	(49,514)	(251,777)	(53,336)	47,669	(306,958)
Net cash provided by (used in) financing activities	423,387	15,853	13,348	(47,669)	404,919

Net increase (decrease) in cash and cash equivalents	266,448	(29,046)	15,853	—	253,255
Cash and cash equivalents, beginning of period	86,937	29,046	68,451	—	184,434
Cash and cash equivalents, end of period	$ 353,385	$ —	$ 84,304	$ —	$ 437,689

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	Six Months Ended June 30, 2017				
	Parent Company	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net cash provided by (used in) operating activities	$ (137,380)	$ 173,301	$ 23,840	$ —	$ 59,761
Net cash provided by (used in) investing activities	(251,400)	(419,849)	(758,933)	236,270	(1,193,912)
Net cash provided by (used in) financing activities	108,675	246,548	641,528	(236,270)	760,481
Net increase (decrease) in cash and cash equivalents	(280,105)	—	(93,565)	—	(373,670)
Cash and cash equivalents, beginning of period	343,941		157,976	—	501,917
Cash and cash equivalents, end of period	$ 63,836	$ —	$ 64,411	$ —	$ 128,247

Note 20. Variable Interest Entities

During the first quarter 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 previously in Note 9, “Investments,” pursuant to the LLC Agreement of GRHL, GRHL authorized and issued a total of 100 Class A Units to SN Comanche Manager. Although the Company did not pay any cash for the Class A Units, the Company’s investment in GRHL represents a VIE that could expose the Company to losses limited to the estimated fair value of the investment. The carrying amounts of the investment in GRHL and the Company’s maximum exposure to loss as of June 30, 2018, was approximately $7.3 million. The Company did not record any earnings from its ownership of the Class A Units for the six months ended June 30, 2018. The Company determined that Blackstone is the primary beneficiary of the VIE as the Company has no significant voting rights in GRHL under the LLC Agreement and no power over decisions related to the business activities of GRHL, other than operation of the properties.

As noted above in Note 9, “Investments,” the Company, via SN Catarina, purchased from a subsidiary of Targa a 10% undivided interest in the SOII Facility in 2015. The Company determined that ownership in the SOII Facility is 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. On June 14, 2017, SN Catarina completed the disposition of the SOII Facility (the "SOII Disposition") for $12.5 million in cash. Prior to the SOII Disposition, we concluded that the investment in SOII Facility is a VIE under the revised guidance because we could not remove Targa as operator and we did not have substantive participating rights. In addition, Targa had 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 had previously accounted for the VIE as an equity method investment and determined that Targa is the primary beneficiary of the VIE as Targa is the operator of the SOII Facility and has the most influence with respect to the normal day-to-day operating decisions of the facility. Prior to the sale, we included the VIE in the "Other Assets - Investments" long-term asset line on the balance sheet.

As noted above in Note 9, "Investments," in November 2016, the Company purchased common units of SNMP for $25.0 million as part of a private equity issuance. Rather than accounting for the investment under the equity method, the Company elected the fair value option to account for its interest in SNMP. The Company's investment in SNMP represents a VIE that could expose the Company to losses limited to the equity in the investment at any point in time. The carrying amounts of the investment in SNMP and the Company's maximum exposure to loss as of June 30, 2018, was approximately $26.8 million.

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Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Company's maximum exposure to loss as of June 30, 2018 and December 31, 2017 (in thousands):

	June 30, 2018	December 31, 2017
Beginning Balance	$ 32,507	$ 39,656
Initial investment in GRHL	—	7,280
Distributions from equity investments	—	(311)
Gain (loss) from change in fair value of investment in SNMP	1,591	(1,591)
Sale of investments	—	(12,527)
Maximum exposure to loss	$ 34,098	$ 32,507

Note 21. Subsequent Events

On July 27, 2018, the Company and Continental Stock Transfer & Trust Company, as rights agent (the "Rights Agent"), entered into a second amendment to the Rights Agreement, dated as of July 28, 2015, between the Company and the Rights Agent (the "Rights Plan") to extend the "Final Expiration Date" of the preferred share purchase rights (the "Rights") pursuant to the Rights Plan from July 27, 2018 to July 26, 2021.

The Board adopted the Rights Plan in an effort to prevent the imposition of significant limitations under Section 382 of the Internal Revenue Code of 1986, as amended (the ''Code''), on its ability to utilize its current NOLs to reduce its future tax liabilities. If the Company experiences an ''ownership change,'' as defined in Section 382 of the Code, the Company's ability to fully utilize the NOLs on an annual basis will be substantially limited, and the timing of the usage of the NOLs could be substantially delayed, which could therefore significantly impair the value of those benefits. In general terms, the Rights Plan works by imposing a significant penalty upon any person or group that acquires 4.9% or more of the outstanding common stock without the approval of the Board (an ''Acquiring Person''). The Rights Plan also gives discretion to the Board to determine that someone is an Acquiring Person even if they do not own 4.9% or more of the outstanding common stock but do own 4.9% or more in value of the Company's outstanding stock, as determined pursuant to Section 382 of the Code and the regulations promulgated thereunder. Stockholders who as of July 28, 2015, owned 4.9% or more of the common stock will not trigger the Rights unless they acquire additional common stock shares, subject to certain exceptions set forth in the Rights Plan. In addition, the Board has established procedures to consider requests to exempt certain acquisitions of the Company's securities from the Rights Plan if the Board determines that doing so would not limit or impair the availability of the NOLs or is otherwise in the best interests of the Company.

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 2017 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, “Sanchez Energy,” 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 U.S. onshore unconventional oil and natural gas resources, with a current focus on the horizontal development of significant resource potential in the Eagle Ford Shale in South Texas. We also hold an undeveloped acreage position in the Tuscaloosa Marine Shale (“TMS”) in Mississippi and Louisiana, which offers future development opportunities. As of June 30, 2018, we have assembled approximately 485,000 gross leasehold acres (283,000 net acres) in the Eagle Ford Shale. For the year 2018, we plan to invest substantially all of our capital budget in the Eagle Ford Shale. We continually evaluate opportunities to grow our acreage and our producing assets through acquisitions. Our successful acquisition of such assets will depend on the opportunities and the financing alternatives available to us at the time we consider such opportunities.

During the fourth quarter of 2017, the Company changed from the full cost method to the successful efforts method in accounting for its oil and natural gas exploration and development activities. Financial information for prior periods has been recast to reflect retrospective application of the successful efforts method. For additional information, see Note 2, “Basis of Presentation and Summary of Significant Accounting Policies” of Part I, Item 1. Financial Statements.

Acquisition and Divestiture Transactions

Listed below is a table of our significant consummated acquisition and divestiture transactions since January 1, 2017:

Transaction	Transaction Date	Transaction Effective Date	Core Area	Net Acreage Acquired	Net Acreage Remaining at 6/30/18	(Purchase) / Disposition Price (millions)

Javelina Disposition	9/19/2017	8/1/2017	Eagle Ford	N/A	N/A	$ 105
Marquis Disposition	6/15/2017	1/1/2017	Eagle Ford	N/A	N/A	$ 50
Comanche Acquisition(1)	3/1/2017	7/1/2016	Eagle Ford, Pearsall	76,000	76,000	$ (1,044)
Cotulla Disposition(2)	12/14/2016	6/1/2016	Cotulla, Eagle Ford	N/A	N/A	$ 167

(1) The acreage and purchase price disclosed in this table includes only acreage and purchase price related to the SN Comanche Assets.

(2) The Cotulla Disposition has been included in the table above to capture the subsequent closings that occurred during the six months ended June 30, 2017. Refer to Note 4, “Acquisitions and Divestitures” for additional detail.

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Javelina Disposition

On September 19, 2017, the Company, through its wholly owned subsidiary, SN Cotulla Assets, LLC (“SN Cotulla”), sold approximately 68,000 undeveloped net acres located in the Eagle Ford Shale in LaSalle and Webb Counties, Texas to Vitruvian Exploration IV, LLC for approximately $105 million in cash, after preliminary closing adjustments (the “Javelina Disposition”). Consideration received from the Javelina Disposition was based on an August 1, 2017 effective date.

Marquis Disposition

On June 15, 2017, the Company, through its wholly owned subsidiary, SN Marquis LLC, sold approximately 21,000 net acres primarily located in the Eagle Ford Shale in Fayette and Lavaca Counties, Texas to Lonestar Resources US, Inc. (“Lonestar”) for an adjusted purchase price of approximately $44 million in cash and approximately $6.0 million in Lonestar’s Series B Convertible Preferred Stock, valued as of the closing date, which subsequently converted into 1.5 million shares of Lonestar’s Class A Common Stock (the “Marquis Disposition”). The consideration received from the Marquis Disposition was based on a January 1, 2017 effective date.

Comanche Acquisition

On March 1, 2017, the Company, through two of its subsidiaries, SN EF UnSub, LP (“SN UnSub”) and SN EF Maverick, LLC (“SN Maverick”), along with Gavilan Resources, LLC (“Gavilan”), an entity controlled by The Blackstone Group, L.P. completed the acquisition of approximately 318,000 gross (155,000 net) acres comprised of 252,000 gross (122,000 net) Eagle Ford Shale acres and 66,000 gross (33,000 net) acres of deep rights only, which includes the Pearsall Shale, representing an approximate 49% average working interest therein (the “Comanche Assets”) from Anadarko E&P Onshore LLC and Kerr-McGee Oil and Gas Onshore LP (together, “Anadarko”) for approximately $2.1 billion in cash (the “Comanche Acquisition”). Pursuant to the purchase and sale agreement entered into in connection with the Comanche Acquisition, (i) SN UnSub paid approximately 37% of the purchase price (including through a $100 million cash contribution from other Company entities) and (ii) SN Maverick paid approximately 13% of the purchase price. In the aggregate, SN UnSub and SN Maverick acquired half of the 49% working interest in the Comanche Assets (approximately 50% and 0%, respectively, of the estimated total proved developed producing reserves (PDPs), 20% and 30%, respectively, of the estimated total proved developed non-producing reserves (PDNPs), and 20% and 30%, respectively, of the total proved undeveloped reserves (PUDs)) (“SN Comanche Assets”). Pursuant to the purchase and sale agreement, Gavilan paid 50% of the purchase price and acquired the remaining half of the 49% working interest in and to the Comanche Assets (and approximately 50% of the estimated total PDPs, PDNPs and PUDs). The Comanche Assets are primarily located in the Western Eagle Ford and are contiguous with our existing acreage, significantly expanding our asset base and production. The effective date of the Comanche Acquisition was July 1, 2016.

Cotulla Disposition

On December 14, 2016, SN Cotulla Assets, LLC (“SN Cotulla”), a wholly-owned subsidiary of the Company, sold approximately 15,000 net acres located in Dimmit, Frio, LaSalle, Zavala and McMullen Counties, Texas (the “Cotulla Assets”) to Carrizo (Eagle Ford) LLC for an adjusted purchase price of approximately $153.5 million, subject to normal and customary post-closing adjustments (the “Cotulla Disposition”). Consideration received from the Cotulla Disposition was based on a June 1, 2016 effective date. During 2017, two additional closings occurred and final post-closing adjustments were made to the purchase price, which resulted in total aggregate consideration of approximately $167.4 million.

2018 Capital Program

Our 2018 capital budget is largely focused on the development of our approximately 283,000 net acres in the Eagle Ford Shale. We anticpate investing approximately $525 million during the year, with over 94% planned for drilling and completion of wells in the Eagle Ford Shale. The remainder will be invested in facilities and leasing activities.

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Basis of Presentation

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

Core Properties

Eagle Ford Shale

We and our predecessor entities have a long history in the Eagle Ford Shale, where, as of June 30, 2018, we have assembled approximately 485,000 gross leasehold acres (approximately 283,000 net acres) and have approximately 7,800 gross (3,550 net) specifically identified drilling locations for potential future drilling. As of June 30, 2018, approximately 691 of these gross drilling locations represented proved undeveloped reserves. These locations were developed using existing geologic and engineering data. The approximately 7,109 additional gross drilling locations are specifically identified non-proven locations that have been identified by our management team. Although these approximate 7,109 gross additional non-proven locations are determined using the same geologic and engineering methodology as those locations to which proved reserves are attributed, they fail to satisfy all criteria for proven reserves for reasons such as development timing, economic viability at Securities and Exchange Commission ("SEC") pricing, and production volume certainty. In evaluating and determining those locations, we also considered the availability of local infrastructure, drilling support assets, property restrictions and state and local regulations. The locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors, and may differ from the locations currently identified. For the year 2018, we plan to invest substantially all of our capital budget in the Eagle Ford Shale.

In 2017, we acquired approximately 252,000 gross (61,000 net) Eagle Ford Shale acres in Dimmit, Webb, La Salle, Zavala and Maverick Counties, Texas through the Comanche Acquisition representing an approximately 24% working interest, which area we refer to as the Comanche area. We anticipate drilling, completion and facilities costs on this acreage to average between $3.0 million and $6.0 million per well. The variability in the cost is largely a factor of lateral lengths, which can vary from approximately 4,400 feet to approximately 11,000 feet. We have identified approximately 5,250 gross (1,275 net) Eagle Ford locations for potential future drilling on our Comanche area.

In the Comanche area, we have a drilling obligation, that, in addition to other requirements in the leases that must be adhered to in order to maintain the acreage position, requires us to complete and equip 60 wells in each annual period commencing on September 1, 2017 and continuing thereafter until September 1, 2022. Up to 30 wells completed and equipped in excess of the annual 60 well requirement can be carried over to satisfy part of the 60 well requirement in subsequent annual periods on a well-for-well basis. As of June 30, 2018, 112 wells had been drilled towards the 60 well commitment that will end on August 31, 2018. As a result, the Company has met its annual drilling commitment in the Comanche area for the current period and has already drilled 30 wells toward the maximum bank of 30 wells for the next annual drilling commitment period that begins on September 1, 2018. For the year 2018, our current capital budget and plans include the drilling of at least the minimum number of wells to maintain access to such undeveloped acreage in the Comanche area.

We have approximately 106,000 net acres in Dimmit, LaSalle and Webb Counties, Texas representing a 100% working interest, which area we refer to as the Catarina area. We anticipate drilling, completion and facilities costs on this acreage to be between $3.0 million and $6.0 million per well based on our current estimates and historical well costs. The variability in the cost is largely a factor of lateral lengths, which can vary from approximately 4,400 feet to approximately 11,200 feet. We have identified greater than 1,050 gross (1,050 net) locations for potential future drilling in our Catarina area.

In the Catarina area, we have a drilling obligation that requires us to drill (i) 50 wells in each twelve month 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 twelve month period on a well-for-well basis. By exceeding the 50 well annual drilling commitment in the two prior years by 20 wells and 18 wells, respectively, the Company maximized the allowable 30 well bank that can be applied towards the current annual drilling commitment period. As of June 30, 2018, SN had drilled 46 wells in addition to the 30 wells banked towards the 50 well annual drilling commitment in the Catarina area that extends from July 1, 2017 to June 30, 2018. As a result, the

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Company has met its annual drilling commitment at Catarina for the current period and drilled 26 wells toward a maximum bank of 30 wells for the next annual drilling commitment period that begins on July 1, 2018.

We have approximately 108,000 net acres in Dimmit, Frio, LaSalle, and Zavala Counties, Texas, which we refer to as the Maverick area. We believe that our Maverick acreage lies in the black oil window, where we anticipate drilling, completion and facilities costs on our acreage to be between $5.5 million and $7.0 million per well based on our current estimates and historical well costs. The variability in the cost is largely a factor of lateral lengths, which can vary from approximately 9,500 feet to approximately 9,800 feet. We have identified greater than 1,050 gross (1,000 net) locations for potential future drilling on our Maverick area.

We have approximately 7,600 net acres in Gonzales County, Texas which we refer to as the Palmetto area. 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 approximately $5.5 million per well based on our current estimates and historical well costs. We have identified greater than 450 gross (215 net) locations for potential future Eagle Ford drilling in our Palmetto area.

Tuscaloosa Marine Shale

As of June 30, 2018, we owned approximately 34,000 net acres in the TMS. The TMS development is currently challenged due to high well costs and depressed commodity prices. We believe that the TMS play has significant development potential as changes in technology, commodity prices, and service prices occur.

Recent Developments

Comanche Integration

Integration of the Comanche Assets continued during the second quarter of 2018. As of June 30, 2018, we had brought 236 gross wells on-line since we closed the transaction on March 1, 2017, including 89 wells during the first half of 2018 and 147 wells during 2017. In addition, as of June 30, 2018, there were 52 wells awaiting completion within the Comanche area. With the Comanche Assets strategically located adjacent to our existing Catarina assets, and in close proximity to our Maverick area, we anticipate substantial and continuing operating synergies and other benefits arising from the scale and concentration of our expanded Eagle Ford position. We believe our continued focus on the Western Eagle Ford, expertise at multi-bench development and efficient cost structure provide us with opportunities to create significant value from the Comanche Assets.

SN UnSub Credit Agreement Amendment

On May 11, 2018, the SN UnSub Credit Agreement was amended in conjunction with the spring redetermination to, among other things, (i) increase the borrowing base from $330 million to $380 million , (ii) lower the applicable margins on borrowings outstanding, (iii) reduce the proven reserves minimum collateral requirement, (iv) reduce the restrictions on SN UnSub’s ability to make certain investments, restricted payments and debt repayments and (v) provide a more permissive maximum hedging covenant. The next regularly scheduled borrowing base redetermination is scheduled in the fourth quarter of 2018.

Outlook

Although commodity and capital markets have shown signs of improvement, we continue to manage our business for the potential of ongoing commodity price volatility. This volatility has significantly influenced our industry and operating environment in the past, and we believe it may again in the future. We face continuing uncertainty with respect to the demand for our products, commodity prices, service availability and costs, and our ability to fund capital projects. As a result, we continue to evaluate the possibility of certain non-core divestitures to improve liquidity and actively manage our portfolio and returns.

We currently expect that the Company’s cash flows and cash on hand will be sufficient to fund our anticipated 2018 operating needs, debt service obligations, capital expenditures, and commitments and contingencies. We continuously evaluate our capital spending, operating and funding activities, with consideration of realized commodity prices and the results of our operations, and may make further adjustments to our capital spending program and related

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financing plans as warranted. We continuously review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

Our 2018 capital budget is largely focused on the development of our approximately 283,000 net acres in the Eagle Ford Shale. We anticpate investing approximately $525 million during the year, with over 94% planned for drilling and completion of wells in the Eagle Ford Shale. The remainder will be invested in facilities and leasing activities.

Results of Operations

Three Months Ended June 30, 2018 Compared to Three Months Ended June 30, 2017

Revenue from Production 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) 2018 vs 2017	
	2018	2017	$	%
Net Production:				
Oil (MBbl)	2,377	2,075	302	15 %
NGLs (MBbl)	2,484	2,130	354	17 %
Natural gas (MMcf)	14,249	14,814	(565)	(4) %
Total oil equivalent (MBoe)	7,236	6,674	562	8 %
Average Sales Price Excluding Derivatives(1):				
Oil ($ per Bbl)	$ 65.86	$ 43.90	$ 21.96	50 %
NGLs ($ per Bbl)	22.76	17.31	5.45	31 %
Natural gas ($ per Mcf)	2.89	3.22	(0.33)	(10) %
Oil equivalent ($ per Boe)	$ 35.13	$ 26.33	$ 8.80	33 %
Average Sales Price Including Derivatives(2):				
Oil ($ per Bbl)	$ 52.80	$ 47.79	$ 5.01	10 %
Natural gas liquids ($ per Bbl)	22.76	17.31	5.45	31 %
Natural gas ($ per Mcf)	3.21	3.16	0.05	2 %
Oil equivalent ($ per Boe)	$ 31.48	$ 27.40	$ 4.08	15 %
Revenues from Production(1)(3):				
Oil sales	$ 156,544	$ 91,096	$ 65,448	72 %

Natural gas liquids sales	56,533	36,873	19,660	53	%
Natural gas sales	41,141	47,735	(6,594)	(14)	%
Total revenues	$ 254,218	$ 175,704	$ 78,514	45	%

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

(3) Excludes revenues related to sales and marketing revenues.

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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,	
	2018	2017
Production:		
Oil - MBbl		
Comanche	1,134	844
Catarina	828	794
Maverick	368	253
Cotulla	—	4
Palmetto	26	75
Marquis	—	99
TMS / Other	21	6
Total	2,377	2,075
Natural gas liquids - MBbl		
Comanche	1,024	860
Catarina	1,445	1,222
Maverick	8	13
Cotulla	—	—
Palmetto	7	15
Marquis	—	20
TMS / Other	—	—
Total	2,484	2,130
Natural gas - MMcf		
Comanche	5,796	5,022
Catarina	8,374	9,565
Maverick	37	67
Cotulla	—	(10)
Palmetto	42	77
Marquis	—	95
TMS / Other	—	(2)
Total	14,249	14,814
Net production volumes:		
Total oil equivalent (MBoe)	7,236	6,674
Average daily production (Boe/d)	79,516	73,341
Average Sales Price (1):		
Oil ($ per Bbl)	$ 65.86	$ 43.90
Natural gas liquids ($ per Bbl)	$ 22.76	$ 17.31
Natural gas ($ per Mcf)	$ 2.89	$ 3.22
Oil equivalent ($ per Boe)	$ 35.13	$ 26.33
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 10.73	$ 9.38
Production and ad valorem taxes	$ 1.96	$ 1.32
General and administrative expenses	$ 4.07	$ 4.45

Depreciation, depletion, amortization and accretion	$ 8.61	$ 6.12
Impairment of oil and natural gas properties	$ 0.03	$ —

(1) Excludes the impact of derivative instruments.

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Net Production. Production increased from 6,674 MBoe for the three months ended June 30, 2017 to 7,236 MBoe for the three months ended June 30, 2018 due to recently completed wells coming online, offset by a decrease in other areas as a result of divestitures during the period. The number of gross wells producing at the period end and the net production for the periods were as follows:

	Three Months Ended June 30,			
	2018		2017	
	# Wells	MBoe	# Wells	MBoe
Comanche	1,657	3,124	1,477	2,541
Catarina	425	3,669	358	3,610
Maverick	63	382	42	277
Cotulla	—	—	—	2
Palmetto	86	40	84	103
Marquis	—	—	—	135
TMS / Other	47	21	14	6
Total	2,278	7,236	1,975	6,674

For the three months ended June 30, 2018, 33% of our production was oil, 34% was NGLs and 33% was natural gas compared to the three months ended June 30, 2017 production that was 31% oil, 32% NGLs and 37% natural gas. The production mix is relatively consistent between the periods due to the similar proportion of oil, NGLs and natural gas production from our producing properties.

Revenues from Production. Sales revenue for oil, NGLs, and natural gas totaled $254.2 million and $175.7 million for the three months ended June 30, 2018 and 2017, respectively. Sales revenue for oil and NGLs for the three months ended June 30, 2018 increased $65.4 million and $19.7 million, respectively, and sales revenue for natural gas decreased $6.6 million, respectively, as compared to the three months ended June 30, 2017. The increase in sales revenue for oil and NGLs is primarily attributable to increased commodity prices and increased production due to recently completed wells coming online. The decrease in sales revenue for natural gas is primarily attributable to a decrease in natural gas prices.

Sales and Marketing Revenues. Beginning in the first quarter of 2018, we entered into commodity purchase transactions with third parties and then subsequently sold the purchased commodity as separate revenue streams. These purchase contracts were entered into to utilize existing firm transportation arrangements. The Company recorded sales and marketing revenues of $5.1 million during the three months ended June 30, 2018 associated with these transactions.

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, 2017 to the quarter ended June 30, 2018 (in thousands, except average sales price).

	Three Months Ended June 30, 2018	2017		Three Months Ended June 30, 2017	
	Production Volume	Production Volume	Production Volume Difference	Average Sales Price	Revenue Increase/(Decrease) due to Production
Oil (MBbl)	2,377	2,075	302	$ 43.90	$ 13,258
Natural gas liquids (MBbl)	2,484	2,130	354	$ 17.31	$ 6,128
Natural gas (MMcf)	14,249	14,814	(565)	$ 3.22	$ (1,821)
Total oil equivalent (MBoe)	7,236	6,674	562	$ 26.33	$ 17,565

	Three Months Ended June 30, 2018	2017		Three Months Ended June 30, 2018	
	Average Sales Price	Average Sales Price	Average Sales Price Difference	Production Volume	Revenue Increase/(Decrease) due to Price
Oil (MBbl)	$ 65.86	$ 43.90	$ 21.96	2,377	$ 52,190
Natural gas liquids (MBbl)	$ 22.76	$ 17.31	$ 5.45	2,484	$ 13,532
Natural gas (MMcf)	$ 2.89	$ 3.22	$ (0.33)	14,249	$ (4,773)
Total oil equivalent (MBoe)	$ 35.13	$ 26.33	$ 8.80	7,236	$ 60,949

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, 2018 by approximately $25.4 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, 2018 by approximately $25.4 million.

Operating Costs and Expenses

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

	Three Months Ended June 30,		Increase (Decrease) 2018 vs 2017	
	2018	2017	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 77,644	$ 62,620	$ 15,024	24%
Exploration expenses	516	4,446	(3,930)	-88%
Sales and marketing expenses	5,086	—	5,086	100%
Production and ad valorem taxes	14,208	8,799	5,409	61%
Depreciation, depletion, amortization and accretion	62,323	40,842	21,481	53%
Impairment of oil and natural gas properties	194	—	194	100%
General and administrative expenses(1)	29,467	29,713	(246)	-1%
Total operating costs and expenses	189,438	146,420	43,018	29%
Interest income	1,528	150	1,378	*
Other income (expense)	6,715	(6,618)	13,333	*
Gain on sale of oil and natural gas properties	1,528	6,022	(4,494)	-75%
Interest expense	(44,590)	(35,961)	(8,629)	24%
Earnings from equity investments	—	242	(242)	-100%
Net gains (losses) on commodity derivatives	(70,044)	59,614	(129,658)	*
Income tax benefit	—	255	(255)	-100%

*Variances deemed to be not meaningful

(1) Includes non-cash stock-based compensation expense of $4.7 million and $4.3 million for the three months ended June 30, 2018 and 2017, respectively, and includes acquisition and divestiture costs of $0.4 million and $2.8 million for the three months ended June 30, 2018 and 2017, 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 24% to approximately $77.6 million for the three months ended June 30, 2018 as compared to $62.6 million for the same period in 2017. The increase is attributable to the increase in operating and transportation costs incurred in the operation of our larger asset base and higher number of producing wells brought online and was partially offset by a decrease in marketing expenses. Our average production expenses increased from $9.38 per Boe during the three months ended June 30, 2017 to $10.73 per Boe for the three months ended June 30, 2018. This increase was due primarily to the increase in production expenses previously described as well as the rising cost environment as oil prices continue to strengthen.

Exploration Expenses. The Company records exploration expenditures as charges against earnings for charges such as exploratory dry holes, exploratory geological and geophysical costs and delay rentals. Exploration expenses decreased from approximately $4.4 million during the three months ended June 30, 2017 to approximately $0.5 million during the three months ended June 30, 2018. The decrease in our exploration expenses was primarily due to fewer exploratory geological and geophysical seismic costs.

Sales and Marketing Expenses. Beginning in the first quarter of 2018, we entered into commodity purchase transactions with third parties and then subsequently sold the purchased commodity as separate revenue streams. These purchase contracts were entered into to utilize existing firm transportation arrangements. The Company incurred expenses to purchase and transport the commodity of approximately $5.1 million for the three months ended June 30, 2018.

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Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at a fixed rate established by state taxing authorities. Ad valorem taxes are paid based upon a percentage, established by state or local taxing authorities, of the fair market value of real and/or business assets. The fair market value of producing properties in Texas is determined using an estimated discounted cash flow approach. Our production and ad valorem taxes totaled $14.2 million and $8.8 million for the three months ended June 30, 2018 and 2017, respectively. The increase in production and ad valorem taxes in the second quarter 2018 compared to the same period in 2017 was primarily due to the increase in production taxes based on the corresponding increase in revenue during the period and an increase in ad valorem taxes related to an increase in wells and an increase in property value as a result of rising commodity prices. Our average production and ad valorem taxes increased from $1.32 per Boe during the three months ended June 30, 2017 to $1.96 per Boe for the three months ended June 30, 2018.

Depreciation, Depletion, Amortization and Accretion. Our DD&A expense increased $21.5 million from $40.8 million ($6.12 per Boe) for the three months ended June 30, 2017 to $62.3 million ($8.61 per Boe) for the three months ended June 30, 2018. Higher production due to additional wells coming online during the three months ended June 30, 2018 as compared to the same period in 2017 resulted in a $3.4 million increase in depletion expense and the increase in the depletion rate resulted in a $18.0 million increase in depletion expense.

Impairment of Oil and Natural Gas Properties. We did not record a proved property impairment during the three months ended June 30, 2018 and 2017. We recorded impairment of $0.2 million ($0.03 per Boe) to our unproved oil and natural gas properties for the three months ended June 30, 2018 due to acreage expiration from changes in development plan. We did not record any impairment to our unproved oil and natural gas properties for the three months ended June 30, 2017. Changes in production rates, levels of reserves, future development costs and other factors will impact our actual impairment analyses in future periods.

General and Administrative Expenses. Our G&A expenses totaled $29.5 million for the three months ended June 30, 2018 compared to $29.7 million for the same period in 2017. Although net G&A remained flat period-over-period, there was a decrease primarily due to a decrease in professional fees, drilling overhead costs, and non-cash stock based compensation expense that was offset by and an increase in our cash stock-based compensation expense and consulting and legal fees. Our G&A expenses per Boe decreased from $4.45 per Boe for the three months ended June 30, 2017 to $4.07 per Boe for three months ended June 30, 2018.

For the three months ended June 30, 2018 and 2017, we recorded non-cash stock based compensation expense (settled in common shares) of approximately $4.7 million ($0.64 per Boe) and expense of $4.3 million ($0.65 per Boe), respectively. The increase in the non-cash stock-based compensation expense amount was caused by additional grants of stock including the PBPS Awards in April 2018 . 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.

We recorded costs associated with insignificant acquisition or divestiture activities of $0.4 million ($0.05 per Boe) for the three months ended June 30, 2018. We recorded costs associated with the Carnero Processing Disposition that are included in G&A of $2.8 million ($0.43 per Boe) for the three months ended June 30, 2017.

Other Income (Expense). For the three months ended June 30, 2018, other income totaled $6.7 million compared to other expense of $6.6 million for the three months ended June 30, 2017. The other income during the three months ended June 30, 2018 relates primarily to a $3.3 million gain associated with the increase in fair value of the investment in SNMP as compared to a loss of $1.5 million during the three months ended June 30, 2017 and a $6.1 million gain associated with the increase in the fair value of the investment in Lonestar as compared to a gain of $0.5 million during the three months ended June 30, 2017. These gains were offset by a loss of $6.1 million on embedded derivatives as compared to a loss of $0.4 million during the comparable period in 2017.

Interest Expense. For the three months ended June 30, 2018, interest expense totaled $44.6 million and included $3.1 million in amortization of debt issuance costs. For the three months ended June 30, 2017, interest expense totaled $36.0 million and included $3.7 million in amortization of debt issuance costs. The increase in interest expense for the three months ended June 30, 2018 relates primarily to the 7.25% Senior Secured Notes issued in February 2018.

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

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and expense. During the three months ended June 30, 2018, we recognized a net loss of $70.0 million on our commodity derivative contracts, which included mark-to-market losses on oil and natural gas derivatives of $35.3 million and $8.4 million, respectively. These losses were primarily the result of increases in commodity prices from the previous reporting period until the end of the current reporting period. In addition, there were settlement losses on oil derivatives of $31.0 million offset by settlement gains of $4.6 million on natural gas derivatives. The settlement gains and losses were primarily a result of the decreases and increases in commodity prices, respectively, from the time the trades were entered until the time of cash settlement for trades that liquidated by their terms during the current period.

During the three months ended June 30, 2017, we recognized a total gain of $59.6 million on our commodity derivative contracts primarily related mark-to-market gains on oil and natural gas derivatives of $40.7 million and $11.7 million, respectively. These gains were primarily the result of decreases in commodity prices from the time the trades were entered until the end of the period. In addition, there were settlement gains on oil derivatives of $8.1 million offset by settlement losses of $0.9 million on natural gas derivatives. Settlement gains and losses are the result of the decrease or increase, respectively, in commodity prices from the time the trades were entered until the time of cash settlement for trades that liquidated by their terms during the current period.

Income Tax Benefit. For the three months ended June 30, 2018, the Company did not record an income tax benefit. Our effective tax rate for the three months ended June 30, 2018 was approximately 0.0% compared to a statutory rate of 21%. The difference between the statutory rate and the Company's effective tax rate is primarily related to a valuation allowance recorded during the period. For the three months ended June 30, 2017, the Company recorded income tax benefit of approximately $0.3 million. Our effective tax rate for the three months ended June 30, 2017 was approximately (0.5%) compared to the maximum statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is primarily related to immaterial differences recorded during the period on warrants issued by the Company to purchase common stock that had a day one difference in estimated fair value for book and tax accounting purposes and an adjustment related to a modification on the Company's separate filing obligations relating to the Comanche Acquisition.

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Six Months Ended June 30, 2018 Compared to Six Months Ended June 30, 2017

Revenue from Production 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) 2018 vs 2017	
	2018	2017	$	%
Net Production:				
Oil (MBbl)	4,898	3,624	1,274	35 %
Natural gas liquids (MBbl)	4,890	3,501	1,389	40 %
Natural gas (MMcf)	28,199	25,270	2,929	12 %
Total oil equivalent (MBoe)	14,488	11,336	3,152	28 %
Average Sales Price Excluding Derivatives(1):				
Oil ($ per Bbl)	$ 63.68	$ 45.36	$ 18.32	40 %
Natural gas liquids ($ per Bbl)	21.64	18.27	3.37	18 %
Natural gas ($ per Mcf)	2.94	3.21	(0.27)	(8) %
Oil equivalent ($ per Boe)	$ 34.56	$ 27.31	$ 7.25	27 %
Average Sales Price Including Derivatives(2):				
Oil ($ per Bbl)	$ 53.07	$ 47.56	$ 5.51	12 %
Natural gas liquids ($ per Bbl)	21.64	18.27	3.37	18 %
Natural gas ($ per Mcf)	3.14	3.07	0.07	2 %
Oil equivalent ($ per Boe)	$ 31.35	$ 27.68	$ 3.67	13 %
Revenues from Production(1)(3):				
Oil sales	$ 311,935	$ 164,372	$ 147,563	90 %
Natural gas liquids sales	105,838	63,973	41,865	65 %
Natural gas sales	82,870	81,201	1,669	2 %
Total revenues	$ 500,643	$ 309,546	$ 191,097	62 %

(1) Excludes the impact of derivative instrument settlements.

(2) Includes the impact of derivative instrument settlements.

(3) Excludes revenues related to sales and marketing revenues.

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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, 2018	2017
Production:		
Oil—MBoe		
Comanche	2,340	1,144
Catarina	1,600	1,563
Maverick	854	526
Cotulla	—	19
Palmetto	57	136
Marquis	—	222
TMS / Other	47	14
Total	4,898	3,624
Natural gas liquids—MBbl		
Comanche	2,061	1,126
Catarina	2,794	2,281
Maverick	17	19
Cotulla	—	1
Palmetto	18	25
Marquis	—	49
TMS / Other	—	—
Total	4,890	3,501
Natural gas—MMcf		
Comanche	11,534	6,885
Catarina	16,481	17,933
Maverick	84	107
Cotulla	—	(9)
Palmetto	100	145
Marquis	—	211
TMS / Other	—	(2)
Total	28,199	25,270
Net production volumes:		
Total oil equivalent (MBoe)	14,488	11,336
Average daily production (Boe/d)	80,044	62,633
Average Sales Price (1):		
Oil ($ per Bbl)	$ 63.68	$ 45.36
Natural gas liquids ($ per Bbl)	$ 21.64	$ 18.27
Natural gas ($ per Mcf)	$ 2.94	$ 3.21
Oil equivalent ($ per Boe)	$ 34.56	$ 27.31
Average unit costs per Boe:		
Oil and natural gas production expenses	$ 10.33	$ 8.88

Production and ad valorem taxes	$ 1.91	$ 1.35
General and administrative expenses	$ 3.58	$ 8.57
Depreciation, depletion, amortization and accretion	$ 8.39	$ 5.93
Impairment of oil and natural gas properties	$ 0.08	$ 0.16

(1) Excludes the impact of derivative instruments.

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Net Production. Production increased from 11,336 MBoe for the six months ended June 30, 2017 to 14,488 MBoe for the six months ended June 30, 2018 due to the addition of the Comanche Assets, offset by a decrease in other areas as a result of divestitures during the period. The number of gross wells producing at the period end and the net production for the periods were as follows:

	Six Months Ended June 30,			
	2018		2017	
	# Wells	MBoe	# Wells	MBoe
Comanche	1,657	6,323	1,477	3,418
Catarina	425	7,141	358	6,833
Maverick	63	885	42	563
Cotulla	—	—	—	18
Palmetto	86	92	84	185
Marquis	—	—	—	306
TMS / Other	47	47	14	13
Total	2,278	14,488	1,975	11,336

For the six months ended June 30, 2018, 34% of our production was oil, 34% was NGLs and 32% was natural gas compared to the six months ended June 30, 2017 production that was 32% oil, 31% NGLs and 37% natural gas. The production mix is consistent between the periods due to the similar proportion of oil, NGLs and natural gas production from our producing properties.

Revenues from Production. Sales revenue for oil, NGLs, and natural gas totaled $500.6 million and $309.5 million for the six months ended June 30, 2018 and 2017, respectively. Sales revenue for oil, NGLs, and natural gas increased $147.5 million, $41.9 million and $1.7 million, respectively, as compared to the six months ended June 30, 2017. The increase in sales revenue for oil and NGLs, and natural gas is primarily attributable to increased production related to the Comanche Acquisition, completed in March 2017 in addition to increased oil and NGL realized prices, offset by decreased natural gas prices.

Sales and Marketing Revenues. Beginning in the first quarter of 2018, we entered into commodity purchase transactions with third parties and then subsequently sold the purchased commodity as separate revenue streams. These purchase contracts were entered into to utilize existing firm transportation arrangements. The Company recorded sales and marketing revenues of $9.9 million during the six months ended June 30, 2018 associated with these transactions.

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, 2017 to the six month ended June 30, 2018 (in thousands, except average sales price).

	Six Months Ended June 30, 2018 Production Volume	2017 Production Volume	Production Volume Difference	Six Months Ended June 30, 2017 Average Sales Price	Revenue Increase due to Production
Oil (MBbl)	4,898	3,624	1,274	$ 45.36	$ 57,784
NGLs (MBbl)	4,890	3,501	1,389	$ 18.27	$ 25,381
Natural gas (MMcf)	28,199	25,270	2,929	$ 3.21	$ 9,412
Total oil equivalent (MBoe)	14,488	11,336	3,152	$ 27.31	$ 92,577

	Six Months Ended June 30, 2018 Average Sales Price	2017 Average Sales Price	Average Sales Price Difference	Six Months Ended June 30, 2018 Production Volume	Revenue Increase due to Price
Oil (MBbl)	$ 63.68	$ 45.36	$ 18.32	4,898	$ 89,779
NGLs (MBbl)	$ 21.64	$ 18.27	$ 3.37	4,890	$ 16,484
Natural gas (MMcf)	$ 2.94	$ 3.21	$ (0.27)	28,199	$ (7,743)
Total oil equivalent (MBoe)	$ 34.56	$ 27.31	$ 7.25	14,488	$ 98,520

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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 $50.1 million, and a 10% decrease in our average realized sales prices, excluding the impact of derivatives, would have decreased our revenues for the six months ended June 30, 2018 by approximately $50.1 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) 2018 vs 2017	
	2018	2017	$	%
OPERATING COSTS AND EXPENSES:				
Oil and natural gas production expenses	$ 149,592	$ 100,620	$ 48,972	49%
Exploration expenses	549	4,797	(4,248)	-89%
Sales and marketing expenses	9,259	—	9,259	100%
Production and ad valorem taxes	27,677	15,323	12,354	81%
Depreciation, depletion, amortization and accretion	121,571	67,245	54,326	81%
Impairment of oil and natural gas properties	1,142	1,845	(703)	-38%
General and administrative expenses(1)	51,887	97,178	(45,291)	-47%
Total operating costs and expenses	361,677	287,008	74,669	26%
Interest income	2,270	507	1,763	*
Other income	10,143	3,917	6,226	*
Gain on sale of oil and natural gas properties	1,528	10,366	(8,838)	-85%
Interest expense	(88,510)	(68,986)	(19,524)	28%
Earnings from equity investments	—	677	(677)	-100%
Net gains (losses) on commodity derivatives	(114,098)	98,496	(212,594)	*
Income tax benefit	—	1,208	(1,208)	-100%

*Variances deemed to be not meaningful

(1) Includes non-cash stock-based compensation expense of $4.3 million and $16.4 million for the six months ended June 30, 2018 and 2017, respectively, and includes acquisition and divestiture costs of $0.7 million and $26.9 million for the six months ended June 30, 2018 and 2017, 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 49% to approximately $149.6 million for the six months ended June 30, 2018 as compared to $100.6 million for the same period in 2017. The increase is attributable to the increase in marketing and transportation costs incurred in the operation of our larger asset base and higher number of producing wells brought online and acquired as part of the Comanche Acquisition in March 2017. Our average production expenses increased from $8.88 per Boe during the six months ended June 30, 2017 to $10.33 per Boe for the six months ended June 30, 2018. This increase was due primarily to the increase in production expenses previously described as well as an increase in service costs from rising commodity prices.

Exploration Expenses. The Company records exploration expenditures as charges against earnings for charges such as exploratory dry holes, exploratory geological and geophysical costs and delay rentals. Exploration expenses decreased from approximately $4.8 million during the six months ended June 30, 2017 to approximately $0.5 million during the six months ended June 30, 2018. The decrease in our exploration expenses was primarily due to fewer exploratory geological and geophysical costs.

Sales and Marketing Expenses. Beginning in the first quarter of 2018, we entered into commodity purchase transactions with third parties and then subsequently sold the purchased commodity as separate revenue streams. These purchase contracts were entered into to utilize existing firm transportation arrangements. The Company incurred expenses to purchase and transport the commodity $9.3 million for the six months ended June 30, 2018.

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Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based upon a percentage of gross revenues or at a fixed rate established by state taxing authorities. Ad valorem taxes are paid based on a percentage, established by state or local taxing authorities, of the fair market value of real and/or business assets. The fair market value of producing properties in Texas is determined using an estimated discounted cash flow approach. Our production and ad valorem taxes totaled $27.7 million and $15.3 million for the six months ended June 30, 2018 and 2017, respectively. The increase in production and ad valorem taxes in the first six months of 2018 compared to the same period in 2017 was primarily due to the corresponding increase in production during the period, and an increase in ad valorem taxes related to an increase in our asset base as a result of the Comanche Acquisition completed in March 2017. Our average production and ad valorem taxes increased from $1.35 per Boe during the six months ended June 30, 2017 to $1.91 per Boe for the six months ended June 30, 2018 primarily due to the increased revenue and asset base as previously described.

Depreciation, Depletion, Amortization and Accretion. Our DD&A expense increased $54.4 million from $67.2 million ($5.93 per Boe) for the six months ended June 30, 2017 to $121.6 million ($8.39 per Boe) for the six months ended June 30, 2018. Higher production as a result of the Comanche Acquisition during the six months ended June 30, 2018 as compared to the same period in 2017 resulted in a $18.8 million increase in depletion expense and the increase in the depletion rate resulted in a $35.6 million increase in depletion expense.

Impairment of Oil and Natural Gas Properties. We did not record a proved property impairment for the six months ended June 30, 2018 and 2017. We recorded impairment of $1.1 million ($0.08 per Boe) and $1.8 million ($0.16 per Boe) to our unproved oil and natural gas properties for the six months ended June 30, 2018 and 2017, respectively, due to acreage expiration for changes in development plan. Changes in production rates, levels of reserves, future development costs and other factors will impact our actual impairment analyses in future periods.

General and Administrative Expenses. Our G&A expenses totaled $51.9 million ($3.58 per Boe) for the six months ended June 30, 2018 compared to $97.2 million ($8.57 per Boe) for the same period in 2017. This decrease was due primarily to additional legal, consulting and professional fees during the six months ended June 30, 2017 associated with the Comanche Acquisition and a decrease in stock-based compensation and additional recovery of drilling overhead costs.

For the six months ended June 30, 2018 and 2017, we recorded non cash stock based compensation expense (settled in common shares) of approximately $4.3 million ($0.30 per Boe) and expense of $16.4 million ($1.45 per Boe), respectively. The decrease in the non-cash stock-based compensation expense amount was caused by a decrease in the Company's stock price. 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.

We recorded costs associated with insignificant acquisition and divestiture activities of $0.7 million ($0.05 per Boe) for the six months ended June 30, 2018. We recorded costs associated with the Comanche Acquisition that are included in G&A of $26.9 million ($2.37 per Boe) for the six months ended June 30, 2017.

Other Income. For the six months ended June 30, 2018, other income totaled $10.1 million compared to other income of $3.9 million for the six months ended June 30, 2017. The other income during the six months ended June 30, 2018 relates primarily to $1.6 million and $6.7 million gains associated with the increase in fair values of the investments in SNMP and Lonestar, respectively, as compared to gains of $0.3 million and $0.5 million, respectively, for the comparable period of 2017. Additionally, we received $4.3 million from income on Company owned equipment as compared to income of $0.9 million during the six months ended June 30, 2017. Offsetting these gains, we incurred a loss of $6.1 million on our embedded derivatives for the six months ended June 30, 2018 as compared to a gain of $0.2 million during the six months ended June 30, 2017.

Interest Expense. For the six months ended June 30, 2018, interest expense totaled $88.5 million and included $9.8 million in amortization of debt issuance costs. For the six months ended June 30, 2017, interest expense totaled $69.0 million and included $6.2 million in amortization of debt issuance costs. The increase in interest expense is primarily attributable to additional interest and debt issuance cost amortization related to the 7.25% Senior Secured Notes issued in February 2018 as well as interest on outstanding borrowings associated with the SN UnSub Credit Agreement.

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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, 2018, we recognized a net loss of $114.1 million on our commodity derivative contracts, which included mark-to-market losses on oil and natural gas derivatives of $56.0 million and $12.0 million, respectively. These losses were primarily the result of increases in commodity prices from the previous reporting period until the end of the current reporting period. In addition, there were settlement losses on oil commodity derivatives of $52.0 offset by settlement gains of $5.9 million on natural gas derivatives. The settlement gains and losses were primarily a result of the decreases and increases in commodity prices, respectively, from the time the trades were entered until the time of cash settlement for trades that liquidated by their terms during the current period.

During the six months ended June 30, 2017, we recognized a total gain of $98.5 million on our commodity derivative contracts primarily related to mark-to-market gains on oil and gas derivatives of $63.1 million and $31.1 million, respectively, associated with the decrease in oil and natural gas prices during the first half of 2017. In addition, the Company had gains from settlements of commodity derivative contracts of $4.3 million. These gains were primarily the result of decreases in commodity prices from the time the trades were entered until the time of cash settlement for trades that liquidated by their terms during the current period.

Income Tax Benefit. For the six months ended June 30, 2018, the Company did not record an income tax benefit. Our effective tax rate for the six months ended June 30, 2018 was approximately 0.0% compared to the statutory rate of 21%. The difference between the statutory rate and the Company's effective tax rate is primarily related to a valuation allowance recorded during the period. For the six months ended June 30, 2017, the Company recorded income tax benefit of approximately $1.2 million. During the six months ended June 30, 2017, the Company issued warrants to purchase common stock that had a day one difference in estimated fair value for book and tax accounting purposes, which caused an income tax benefit during the period. Our effective tax rate for the six months ended June 30, 2017 was (1.8%) compared to the statutory rate of 35%. The difference between the statutory rate and the Company's effective tax rate is primarily related to the recording of certain deferred tax liabilities associated with the Comanche Acquisition that were recorded directly to equity, whereas the correlating movement in the valuation allowance was required to run through income tax expense.

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, 2018, our critical accounting policies were consistent with those discussed in our 2017 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, capital expenditures 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, 2018, we had approximately $437.7 million in cash and cash equivalents, $25.0 million in available borrowing capacity under the Credit Agreement, and $212.5 million in available borrowing capacity under the SN UnSub Credit Agreement, resulting in aggregate liquidity of approximately $675.2 million. For a description of

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current and previous credit agreements along with the indentures covering our Senior Notes refer to Note 7, “Debt” of Part I, Item 1. Financial Statements. Other potential sources of capital and liquidity also include, among other things, our securities that can be issued pursuant to our shelf registration statement filed with the SEC, including pursuant to our $75 million at-the-market equity distribution program we entered into on May 25, 2017.

On February 14, 2018, we issued $500 million in aggregate principal amount of the 7.25% Senior Secured Notes and amended and restated our prior revolving credit facility to, among other things, (i) reduce its size from a $350 million borrowing base with a $300 million aggregate commitment amount to a $25 million commitment to provide primarily for working capital and letters of credit, (ii) extend the maturity from 2019 to 2023, (iii) remove all material financial maintenance covenants and (iv) provide for the continued ability to hedge. See Note 7, “Debt” of Part I, Item 1. Financial Statements.

We currently expect that the Company’s cash flows and cash on hand will be sufficient to fund our anticipated 2018 operating needs, debt service obligations, capital expenditures, and commitments and contingencies. We continuously evaluate our capital spending, operating and funding activities, with consideration of realized commodity prices and the results of our operations, and may make further adjustments to our capital spending program and related financing plans as warranted. We continuously review acquisition and divestiture opportunities involving third parties, SNMP and/or other members of the Sanchez Group.

Our 2018 capital budget is largely focused on the development of our approximately 283,000 net acres in the Eagle Ford Shale. We anticpate investing approximately $525 million during the year, with over 94% planned for drilling and completion of wells in the Eagle Ford Shale. The remainder will be invested in facilities and leasing activities.

We may from time to time seek to retire or purchase our outstanding debt as well as our outstanding preferred equity securities through cash purchases and/or exchanges for equity securities and/or debt securities, as applicable, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Cash Flows

Our cash flows for the six months ended June 30, 2018 and 2017 (in thousands) are as follows:

Six Months Ended

	June 30, 2018	2017
Cash Flow Data:		
Net cash provided by operating activities	$ 155,294	$ 59,761
Net cash used in investing activities	$ (306,958)	$ (1,193,912)
Net cash provided by financing activities	$ 404,919	$ 760,481

Net Cash Provided by Operating Activities. Net cash provided by operating activities was $155.3 million for the six months ended June 30, 2018 compared to cash provided by operating activities of $59.8 million for the same period in 2017. This increase was related to higher revenues due to the impact of higher average commodity prices for oil and NGLs between these periods and increased production related to the SN Comanche Assets acquired in March 2017. The increase was partially offset by a decrease in average realized prices for natural gas and cash outflows for settlements on commodity derivatives for the six months ended June 30, 2018 compared to cash inflows for settlements on commodity derivatives for the six months ended June 30, 2017.

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 $307.0 million for the six months ended June 30, 2018 compared to $1.2 billion for the same period in 2017. Capital expenditures for leasehold and drilling activities for the six months ended June 30, 2018 totaled $307.7 million, primarily associated with bringing

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117 gross wells on-line. In addition, we received $2.8 million related to the post-closing adjustments for the Comanche Acquisition during the six months ended June 30, 2018.

For the six months ended June 30, 2017, we purchased the SN Comanche Assets for approximately $1,039 million. We incurred capital expenditures for leasehold and drilling activities of $212.9 million, primarily associated with bringing 71 gross wells on-line, including 42 drilled-but-uncompleted wells acquired in the Comanche Acquisition. We received a total of $16.8 million for the additional closings of the Cotulla Disposition that occurred in January and April 2017. We received $44.0 million at the closing of the Marquis Disposition and an additional $12.5 million for the SOII Disposition. In addition, we invested $15.1 million in other property and equipment during the six months ended June 30, 2017.

Net Cash Provided by Financing Activities. Net cash flows provided by financing activities totaled $404.9 million for the six months ended June 30, 2018 compared to $760.5 million for the same period in 2017. During the six months ended June 30, 2018, we issued $500 million in 7.25% Senior Secured Notes (net of discounts of $5.1 million) and had incremental borrowings of $45 million. Additionally, we made repayments on the prior credit facility of $95 million and payments on the SN UnSub credit facility of $8.0 million. We also made payments of $9.9 million for distributions to holders of the SN UnSub Preferred Units and paid dividends on our Series A and B Preferred Stock of $8.0 million.

During the six months ended June 30, 2017, we entered into the SN UnSub Credit Agreement in conjunction with the Comanche Acquisition, we had borrowings under the UnSub Credit Agreement of $198.5 million and issued the SN UnSub Preferred Units for $500 million. Further, we issued common stock for $135.9 million (net of underwriting discounts of $7.8 million). We made payments of $45.5 million for deferred financing costs associated with the SN UnSub Credit Agreement and issuance costs for the SN UnSub Preferred Units, collectively. In addition, we made payments of $1.0 million of employee taxes via withholding shares associated with stock-based compensation and $27.4 million for tax distributions to holders of the SN UnSub Preferred Units.

Off Balance Sheet Arrangements

As of June 30, 2018, we did not have any off balance sheet arrangements.

Commitments and Contractual Obligations

Refer to Note 17, “Commitments and Contingencies” of Part 1, Item 1. Financial Statements for a description of lawsuits pending against the Company.

There have been no material changes in our contractual obligations during the six months ended June 30, 2018, other than those disclosed in Note 17, “Commitments and Contingencies” of Part 1, Item 1. Financial Statements.

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 primary market risk exposure relates to the prices we receive for our oil, natural gas and NGL production. The prices we ultimately realize for our oil, natural gas and NGLs are based on a number of variables, including prevailing index prices attributable to our production and certain differentials to those index prices. Pricing for oil, natural gas and NGLs is volatile and unpredictable, and this volatility is expected to continue in the future. In addition, the prices we receive for our oil, natural gas and NGLs depend on many factors outside of our control, such as the supply and demand for oil, natural gas and NGLs, the relative strength of the global economy and the actions of OPEC.

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To reduce the impact on the Company's business and results of operations from fluctuations in the prices we receive for oil, natural gas and NGLs, 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 transactions 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 or extend the notional quantity settlement period 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 Credit Agreement, the SN UnSub Credit Agreement and the terms of SN UnSub's organizational documents 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 participants. Any derivatives that are with (x) lenders to the SN UnSub Credit Agreement, or (y) counterparties designated as secured under the Credit Agreement are, in each case, collateralized by the assets securing the applicable facility, and, therefore, do not currently require the posting of cash collateral. Any derivatives that are with (x) non-lender counterparties, as designated under the SN UnSub Credit Agreement, or (y) counterparties that are not designated as secured under the Credit Agreement are, in each case, unsecured and do not require the posting of cash or other collateral. It is never the Company's intention to enter into derivative contracts for speculative trading purposes. Please refer to Note 8, "Derivative Instruments" in Part I, Item 1. Financial Statements for a description of all of our derivatives covering anticipated future production as of June 30, 2018.

The prices at which we enter into commodity derivative contracts covering our production in the future will be dependent upon conditions in the commodity and financial markets at the time we enter into these transactions, which may result in higher or lower hedge prices for oil, natural gas and NGLs, if any, under these contracts as compared to the hedge prices under our current contracts. Accordingly, our hedging strategy may not protect us from significant or sustained declines in the prices of oil, natural gas and NGLs for future production. Conversely, our hedging strategy may limit our ability to realize incremental cash flows from commodity price increases during periods for which we have hedged our production. As such, our hedging strategy may not prove effective in adequately protecting us from changes in the prices of oil, natural gas and NGLs that could have a significant adverse effect on our liquidity, business, financial condition and results of operations.

At June 30, 2018, the fair value of our commodity derivative contracts was a net liability of approximately $122.3 million. A 10% increase in the oil and natural gas index prices above the June 30, 2018 prices would result in a decrease in the fair value of our commodity derivative contracts of $70.1 million; conversely, a 10% decrease in the oil and natural gas index price would result in an increase of $70.5 million.

Interest Rate Risk

At the Company's election, borrowings under the Credit Agreement or the SN UnSub Credit Agreement may be made on a variable alternate base rate ("ABR") or a Eurodollar (LIBOR) rate, plus an applicable margin determined based on the utilization of available borrowing capacity, as defined in the applicable credit agreement. As of June 30, 2018, there were no borrowings outstanding under the Credit Agreement and $167.5 million in borrowings outstanding under the SN UnSub 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, 2018. 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, 2018. Our 7.25% Senior Secured Notes bear a fixed interest rate of 7.25% with an expected maturity date of February 15, 2023, and we had $500 million outstanding as of June 30, 2018.

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Our Non-Recourse Subsidiary Term Loan (as defined in “Note 7. Debt” of Part I, Item 1. Financial Statements) bears a fixed interest rate of 4.59% with an expected maturity date of August 31, 2022, and we had approximately $4 million outstanding as of June 30, 2018.

The credit facility which we assumed through a non-recourse subsidiary when we acquired the equity in Sanchez Resources bears a variable interest rate and, although the original maturity date was August 7, 2018, prior to its acquisition by the Company, the administrative agent and the lenders accelerated the obligations due under the credit facility, which continues to bear interest on the outstanding and unpaid borrowings. As of June 30, 2018, there was approximately $24.0 million in borrowings past due with no availability to borrow additional funds under that credit facility.

As of June 30, 2018, we did not have any interest rate derivative contracts in place. If we incur significant debt with a risk of fluctuating interest rates in the future under the Credit Agreement, SN UnSub Credit Agreement, or other debt instruments, we may enter into interest rate derivative contracts on a portion of our then outstanding debt to mitigate the risk of fluctuating interest rates.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

We carried out an evaluation, under the supervision and with the participation of management, including our 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, 2018 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 17, “Commitments and Contingencies” of Part I, Item 1. Financial Statements.

Item 1A. Risk Factors

Consider carefully the risk factors under the caption “Risk Factors” under Part I, Item 1A in our 2017 Annual Report, together with all of the other information included in this Quarterly Report on Form 10-Q; in our 2017 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.

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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

3.1		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).
3.2		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).
3.3		Amended and Restated Bylaws, dated as of December 13, 2011 (filed as Exhibit 3.2 to the Company's Current Report on Form 8 K on December 19, 2011 (File No. 001 35372) and incorporated herein by reference).
3.4		Certificate of Amendment to Restated Certificate of Incorporation of Sanchez Energy Corporation, dated May 24, 2018 (filed as Exhibit 3.1 to the Company’s Current Report on Form 8-K on May 24, 2018 (File No. 001-35372) and incorporated herein by reference).
4.1	(a)	Fourth Supplemental Indenture (7.75% Senior Notes due 2021), dated as of April 3, 2018, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company, as trustee.
4.2	(a)	Second Supplemental Indenture (6.125% Senior Notes due 2023), dated as of April 3, 2018, by and among Sanchez Energy Corporation, SN EF Maverick, LLC, Rockin L Ranch Company, LLC, the existing guarantors and Delaware Trust Company, as trustee.
4.3	(a)	First Supplemental Indenture (7.25% Senior Secured First Lien Notes due 2023), dated as of April 3, 2018 among Sanchez Energy Corporation, the guarantors party thereto, Delaware Trust Company, as trustee and Royal Bank of Canada, as collateral trustee.
10.1	*	Form of Performance Cash-Settled Phantom Stock Agreement (filed as Exhibit 10.1 to the Company’s Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference).
10.2	*	Form of Performance Share-Settled Phantom Stock Agreement (filed as Exhibit 10.2 to the Company’s Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference).
10.3	*	Form of Restricted Stock Agreement (filed as Exhibit 10.3 to the Company’s Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference).
10.4	*	Form of Phantom Stock Agreement (filed as Exhibit 10.4 to the Company’s Current Report on Form 8 K on April 23, 2018, and incorporated herein by reference).

10.5	First Amendment to First Lien Credit Agreement, dated as of May 11, 2018, among SN EF UnSub, LP, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8 K on May 15, 2018, and incorporated herein by reference)

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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 Taxonomy Extension Presentation Linkbase Document

(a) Filed herewith.

(b) Furnished herewith.

* Management contract or compensatory plan or arrangement

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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 7, 2018.

SANCHEZ ENERGY CORPORATION

By: /s/ Kirsten A. Hink
Kirsten A. Hink
Senior Vice President and Chief Accounting Officer

(Duly Authorized Officer)

By: /s/ Howard J. Thill
Howard J. Thill
Executive Vice President and Chief Financial Officer

(Principal Financial Officer)